JOINT PUBLIC MEETING

OF THE

CALIFORNIA POWER AUTHORITY
CALIFORNIA ENERGY COMMISSION
CALIFORNIA PUBLIC UTILITIES COMMISSION

In the Matter of:)
)
DRAFT ENERGY ACTION PLAN)
Goals II, IV and V)
_________________________________)

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

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SACRAMENTO, CALIFORNIA

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CALIFORNIA ENERGY COMMISSION

William J. Keese, Chairman

Arthur H. Rosenfeld

James Boyd

John L. Geesman

B.B. Blevins

STAFF

Bob Therkelsen, Executive Director

Tim Tutt

Don Kondoleon

Mark Rawson

Margret Kim, Public Adviser

CALIFORNIA PUBLIC UTILITIES COMMISSION

Michael Peevey, President

Susan Kennedy

Geoffrey Brown

STAFF

John Galloway

Barbara Hale, Director Strategic Planning

Kerry Hattevik

Dan Adler, Regulatory Analyst

CALIFORNIA POWER AUTHORITY

Sunne McPeak, Acting Chairwoman

Barbara Lloyd on behalf of Phil Angelides

Donald Vial

STAFF

Laura Doll, CEO

ALSO PRESENT

Joseph F. Desmond, President & CEO
Infotility
on behalf of Silicon Valley Manufacturing Group

Mike Chrisman, Secretary for Resources
The Resources Agency

Dan A. Emmett, CEO
Douglas Emmett Realty Advisors

Dan Skopec, Deputy Cabinet Secretary
Office of Governor Arnold Schwarzenegger

James L. Sweeney, Professor
Management Science and Engineering
Stanford University

Jim Detmers, Vice President, Grid Operations
California Independent System Operator

Gary L. Schoonyan, Director
Southern California Edison Company

James C. Feider, Chairman
Maury Kruth, Executive Director
Transmission Agency of Northern California

John W. Schumann, Director
Los Angeles Department of Water and Power

Armando J. Perez, Director of Grid Planning
California Independent System Operator

ALSO PRESENT

Samuel L. Wehn
Babcock & Brown Power Operating Partners LLC

Les Guliasi, Director State Agency Relations
Pacific Gas and Electric Company

Dan G. Ozenne, Regulatory Policy
Sempra Energy Utilities

Jan Smutny-Jones, Executive Director
Independent Energy Producers

Jarry Jordan, Executive Director
California Municipal Utilities Association

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P R O C E E D I N G S

10:19 a.m.

CHAIRMAN KEESE: We'll call this joint meeting of California Public Utilities Commission, California Power Authority and California Energy Commission to order.

I'm Bill Keese, Chairman of the Energy Commission. And we're pleased to be joined up here by my fellow Commissioner, John Geesman; Don Vial, Commissioner of the Power Authority -- Director of the Power Authority; President Mike Peevey of the Public Utilities Commission; Commissioner Jim Boyd; and I'm sorry, Barbara? Barbara Lloyd representing Phil Angelides; Geoff Brown, Commissioner at the PUC; B.B. Blevins of the Commission; and Art Rosenfeld of the Commission.

Susan Kennedy will be joining us shortly. She's delayed in traffic. I'm sure that Sunne McPeak will also be joining us. I believe that is our attendance from the respective Commissions.

We're pleased we're able to be joined by, as I said, our esteemed guests. The Steering Committee, our tripartite body, in discussing what we've been able to accomplish in the last year, and looking forward to future years felt that what we have been able to do is establish joint activities between our agencies.

So that over at the Public Utilities Commission and here at the Energy Commission we have joint processes in which the Commissioners are working together on aspects of the same issue. And we have staffs that are working in each others' processes.

You're familiar with our action plan, or should be. We'll be hearing from the utilities later this afternoon on what they're doing in the implementation of it.

It's our hope that as we move forward we can incorporate other agendas of the Administration that fit into this joint activity. It's also our hope that we can introduce the successes that we've had between our entities into the policymaking of this Administration. And for that reason we have invited a number of the policymakers here. And I'm going to introduce them briefly. And if they have a few comments to say, we'd welcome it at this time.

So, just starting on my far right, Joe

Desmond.

MR. DESMOND: Thank you, Mr. Chairman, appreciate the opportunity. I'm really here on behalf of the Silicon Valley Manufacturing Group and just wanted to indicate that we've been working very closely with both the independent generators, retail marketers, many of the other business organizations on this issue of resource adequacy. And it relates directly to some of the western renewable generation information system activities that I know are part of this joint energy agency action plan.

So, as we go through the day hopefully we'll be able to offer up some thoughts and ideas to help identify how to link those two issues.

CHAIRMAN KEESE: Thank you. Secretary Mike Chrisman, Secretary of Resources.

SECRETARY CHRISMAN: Thank you, Chairman Keese. Not much more to add other than thank you all for taking time out of your very valuable schedules to be a part of this discussion. Thanks to the Energy Commission and the Public Utilities Commission for your willingness to engage in these discussions.

The fact that we have two Commissions

working so closely together I think is a great model for state government; like that very much. We like that very much. I know the Governor feels strongly about that. And we're here to support your efforts in any way we can. Thank you.

CHAIRMAN KEESE: Thank you very much. And on my left we'll start with Dan Emmett.

MR. EMMETT: I'm Dan Emmett from Los Angeles. I'm in the real estate business; run a company that owns a lot of real estate down there. The Governor has asked me to help put together a group that is going to give advice on how we can do more to save energy, especially with people like myself.

And we put together a group of very knowledgeable people from government and the private sector to try to come up with some suggestions about what existing tools can be enhanced and what new tools there might be that we can bring to bear on energy conservation.

The Governor is a strong believer in this and it's a strong part of his platform. And we're going to try to give him some solid advice. And it's great to see a collaborative effort like this. You guys have come a long way, and we've got a ways to go. Thank you.

CHAIRMAN KEESE: Thank you very much. Jim Sweeney.

DR. SWEENEY: Hi, I'm Jim Sweeney from Stanford University. I've been involved in electricity policy for some time, and I worked with the Governor's Office during the transition.

I've been just actually quite impressed by the fundamental change that I've seen from three agencies -- well, at one time, two agencies, and three agencies that didn't naturally have to work together, and yet it put together a plan that I think goes such a long ways in the right direction towards energy policy. And I'm just pleased to see that continuing to happen.

CHAIRMAN KEESE: Thank you very much. And approaching the microphone from the left is Dan Skopec from the Governor's Office, Policy.

DEPUTY CABINET SECRETARY SKOPEC: Hi. I'm Dan Skopec; I'm Deputy Cabinet Secretary for the Governor's Office handling energy resources and CalEPA.

CHAIRMAN KEESE: Thank you, Dan. We're going to hold Mr. Detmers till later; he's going to be featured prominently.

We're joined by Sunne McPeak, Acting Chair of the Power Authority. Okay, I think with that we'll get right into our program.

You have before you up here the action plan implementation matrix. So I'd accept input from any of the Commissioners on that matrix that they'd like to point out very briefly. I would ask that you forego questions on the renewable resource goal, electricity transmission and distributed generation because we'll be taking up those issues more fully later on.

We have submitted this implementation matrix to the Governor's Office, as requested, on December 31st. And I believe that a number of the audience will respond to it later on in our program.

ACTING CHAIRWOMAN McPEAK: Mr. Chairman, if I might just report on an item in the matrix that isn't on our agenda for further discussion, but was before us at the last meeting, and that we briefly discussed at the Steering Committee meeting last week, and that has to do with efficiency measures and building codes.

And let me begin by saying how good it is to have Secretary Chrisman here, to have another member of the Cabinet, and I know that we've invited Secretary Tamminen who will be able to join us in the future, and who's been very interested in energy.

And we've also then had the discussion with Secretary Aguire, who is Secretary of State and Consumer Affairs. But within that agency is the Department of General Services, for which we also had a lot of discussion last week with respect to solar on state buildings.

With respect to the Uniform Building Code, which is in Housing and Community Development, so I'm wanting to comment on an item that is in our matrix and also an implementation responsibility in a department within the agency that I have responsibility for now.

As we discussed last week, and also at our last quarterly meeting, we really want to get our input from the energy action plan into the UBC before it is adopted. The Energy Commission has provided, as you do in your cycle, the input for the 2005; and therefore we thought perhaps we couldn't get input until 2008. Well, as we all discussed, that was too -- that's too long a delay.

And so we are intervening to look at what is possible, particularly with dynamic pricing and advanced metering, advanced metering to become ready for dynamic pricing.

And so as the PUC goes through your proceedings and we continue to work on dynamic pricing I would like to invite as much input as quickly as possible as to what would make sense, especially for retrofit, remodeling and new construction for the implementation and installation of advanced metering.

CHAIRMAN KEESE: Thank you. Commissioner Rosenfeld.

COMMISSIONER ROSENFELD: Mr. Chairman, I do have some, a couple of comments to make on the load management and demand response side of the matrix.

There's some good news. Right now air conditioners in California have to have an efficiency rating, which is known as SEER, of 10. And there's been an interesting controversy. The last few days of the Clinton Administration the Department of Energy recommended to raise that 30 percent to 13, which would make a lot of difference for us. In the early days of the Bush

Administration they set it back to 12.

NRDC sued the Bush Administration with quite a few states, including California, as Friends of the Court. And in Maryland court, since we met last, the court ruled that you cannot set back from 13 to 12. So we're at 13. It may not last. American Refrigeration Institute is now counter-suing in the State of Virginia. But for the moment we're up 30 percent.

The other good news is that the California PIER program, Public Interest Energy Research here at the CEC, is now doing a serious study of what would happen if one broke the country up into three air conditioning zones, because the west is really very different from the soggy southeast; and optimized an air conditioner for the hot dry west using Phoenix or L.A. weather.

And it's beginning to look as if we can get another 10 or 15 percent out of doing that, which would give us conceivably a huge jump in planning from 10 where it is now to something close to 15. And since 30 percent of our peak load is air conditioning, that's really encouraging news.

So, thank you for the time to say that.

CHAIRMAN KEESE: Thank you very much. Anyone else here wish to raise issues at this point?

COMMISSIONER BOYD: Mr. Chairman.

CHAIRMAN KEESE: Commissioner Boyd.

COMMISSIONER BOYD: Just a quick comment on the item 6, which has to do with natural gas. As identified in the matrix the CEC, who has worked very closely with all the agencies represented here, and probably most of the stakeholders of the public represented here, of course, turned its Integrated Energy Policy Report in to the new Governor in December. And we're anxiously awaiting some feedback on that.

But, it addresses quite significantly the issues with respect to natural gas that face us here in California. The PUC has initiated its OIR on which the Energy Commission has worked very closely and collaborated closely with the PUC on the subject of gas.

And thirdly, as many of us up here know and recognize, there have been a large number of forums in California over the past several months since we last met discussing the subjects of natural gas in general, or the LNG component of natural gas specifically, including several of us who were just together last week, in what I thought was a very significant discussion of the subject.

So I just wanted to report that certainly the subject has the attention of both government and industry and stakeholders. And we look forward to additional collaboration and hopefully quite a bit of progress in advancing the attention to this particular energy need in California.

Thank you.

CHAIRMAN KEESE: Thank you very much. The one issue that I will raise that came up at the Steering Committee, and we decided to have further conversation about, was the relationship of petroleum fuels to our energy mix. And the fact that -- the implications of the petroleum area are, if not greater, at least as great as the implications of natural gas and electricity.

So, we decided we'd take a look at whether we should involve the petroleum area in this forum. That waits for a later date.

Well, that puts us, I think, reasonably

close to our agenda. So, topic 3 is to accelerate the state's goal for renewable resources. And I believe that Mr. Tutt and Mr. Adler, and Mr. Galloway -- wherever you're going to do it. You're going to give us an overview, as I understand.

(Pause.)

MR. GALLOWAY: I'm John Galloway from the Public Utilities Commission. I'll give an overview of the RPS as it stands now, and discuss accelerating the goals of the RPS so that we meet a 20 percent goal by 2010. The legislation originally called for 2017. The energy action plan has moved that up to 2010.

So to that end the key activity that will happen at the Public Utilities Commission imminently is the opening of a new rulemaking this month to address the remaining RPS implementation issues. As many of you are aware, we issued a decision in June of last year which set out the framework for the RPS, established a lot of the process for the program, but left some issues that remained to be resolved, such as the setting of a market price reference. I'll go over each of the elements of these in just a moment.

But the overall goal, as I mentioned, is reaching 20 percent by 2010. And the utilities are starting from a baseline today roughly of 11 percent. So we're talking about a 9 percent increase. But this is based on 2001 retail sales.

And so here I've listed where approximately we're starting from in 2002 in absolute numbers of megawatts and the gigawatt hours of energy delivery; and discuss the interim procurement authority that was granted by the CPUC to the IOUs under procurement decisions and an assigned-Commissioner ruling back in August, which, you know, said the utilities can go forward with renewables procurement, you know, absent the full fleshed-out RPS. And the utilities have procured more than 660 megawatts of renewable capacity during that time.

One of the next steps is to direct the IOUs to file renewable procurement plans. Many of you are aware that we've, you know, gone through a round of short-term and long-term procurement plans. What the renewable procurement plans do is sort of look strictly at the renewables procurement piece of those plans to say what do we expect to -- you know, what kind of products do we expect to see over the next several years to meet our RPS targets.

That is going to necessarily include the accelerated procurement targets. Many of you are familiar with the legislation which says that utilities will achieve 1 percent per year until they reach 20 percent. So we're going to have the utilities look at the accelerated scenario on an annual basis; therefore, those targets may exceed the statutory requirement.

One thing that the procurement plans will also do is trigger a first round of solicitation. So when those plans are approved they contain a request for offers. So at that time that triggers the first round of solicitations.

One of the key things we need to do as we move into this process and look at accelerating the goals is insuring, you know, that we have adequate resource development, transmission planning and the efficient use of public goods charge funds.

What the public goods charge, as it relates to renewables, is doing in the RPS is funding the above-market costs. So as the

Commission establishes a market price reference, that sort of becomes the threshold at which the utility responsibility for the purchase of the renewable power ends and the above-market cost would be paid from the public goods charge.

Under an accelerated scenario one thing that we have to monitor very closely, in collaboration with the Energy Commission, is the effect of increased pressure on those funds as more resources come online to meet that goal.

Between the 29th and 3rd of February the IOUs filed compliance reports telling us where they were in 2003. And we'll use those reports as a basis of, you know, looking at their 2004 procurement targets. And we also need to establish the baseline as a part of that process.

And as I stated earlier, and I'll again emphasize, that that annual procurement target may increase under the accelerated scenario. The utilities are at different stages in the renewables procurement; some are further along than others, and that has to be taken into consideration.

We're going to hold workshops in March and April to further develop the methodology for determining market price reference. As I mentioned, that's sort of the threshold and the basis for bid evaluation, and also establishes the threshold for supplemental energy payments. So we see that as a very important and a very imminent and pressing need.

There are several pieces of the RPS and admittedly this is probably the largest and most critical.

And we'll be issuing a white paper this month to focus that discussion in the workshops. And following that, the Commission will adopt a final methodology, by decision, in May or June.

One of the other large items of the RPS is to establish standard contract terms and conditions so that renewable developers, you know, know what this -- the contracts are clear, they're standard and uniform across the utilities. One thing that we're doing is establishing the terms, themselves. In other words, what we think needs to be made standard. And then parties will come back following that ruling to propose the actual contract language. And we expect that that will occur in May of this year.

So I've already mentioned the first two

elements of the RPS. The third here is the least cost and best fit resource assessment. In other words, looking at the least cost renewable resources and how they're fitting into the utilities' portfolio.

There are a couple of key items that remain there, such as looking at integration costs and transmission adders. So in other words, looking at where resources are located and how we need to have some orderly transmission development to reach those resources.

And the fourth element I've discussed, which is the renewable procurement plan.

The reason I call these key elements is in order to get to the first solicitation these are the elements that must be in place by statute. And once these are in place, the IOUs will conduct solicitations.

We expect the first one to occur between June and September of this year. There are a number of factors that affect that schedule; one of which is, of course, the approval of the renewable procurement plans and the kind of review process that goes into reviewing those plans before they are approved.

And to emphasize this, you know, I've highlighted a lot of steps that the PUC is undertaking to implement the RPS and to accelerate the goals. But it's very key to note that even though the legislation gives the PUC and the Energy Commission very distinct tasks, we're really working together collaboratively to implement those rules and to make sure that the accelerated goal is reached.

And along those lines, now to talk about the Energy Commission's role in RPS, is Tim Tutt, the Director of the Energy Commission's renewable energy program.

MR. TUTT: Thank you, John. We are collaborating well with the PUC. The CEC was given the responsibility under 1038 and 1078 to do two parts of the RPS. One is to develop allocation rules for supplemental energy payments. And the second part is to do a tracking system to make sure that the RPS generation is sold once and only once. You know, used appropriates and developed appropriately.

I'm going to talk about those two parts of the progress that we've made and what we're expecting to happen. I'm also going to talk about a little bit about the integration cost work that we've done in collaboration with the PUC.

On the developing the rules for the RPS eligibility and rules for supplemental energy payments, we released three draft guidebooks in January '04 actually. And on February 5th we held a hearing on those guidebooks to take public comment. We're currently reviewing that public comment and intending to send out a final set of guidebooks, I believe, on the 19th of this month, March 19th. And adopt them in April.

Those three guidebooks are the Renewable Portfolio Standard Eligibility Guidebook; the New Renewable Facilities Program Guidebook; and the updated Overall Guidebook for the Renewable Energy Program.

The eligibility standard guidebook describes proposed RPS eligibility requirements for instate and out-of-state facilities. It talks about what you have to do to be renewable; what kind of constraints there are on out-of-state versus instate facilities.

It outlines the process for certifying renewable resources as eligible for the RPS and supplemental energy payments. We ask these resources to certify so that we have some information about them as they move forward and as things change in their circumstances.

It also describes the proposed interim tracking system to track and verify compliance with RPS. This interim tracking system is one that's based on our work under the electricity disclosure law, SB-1305, verifying claims that are made in power content labels.

We are developing a more comprehensive electronic tracking system which I will be talking about later in the presentation.

The new renewable facilities program guidebook proposes how to qualify for and receive supplemental energy payments for above-market costs. Facilities would have to be certified as eligible to meet the RPS and be new under the draft guidebook. And that means, under the language of the guidebook, they either have to commence operation or be repowered on or after January 1, 2002. Only those new facilities are eligible for supplemental energy payments according to SB-1038.

Applicants would participate in RPS solicitations by IOUs, as John has described, after the process of putting the rules in place and having the procurement plans. Solicitations will occur. And winning bidders with CPUC approved power purchase contracts may receive supplemental energy payments to the extent that their bids, as they win, are above the market price references that are established for those facilities, or those solicitations.

The overall program guidebook is one that sort of describes for our renewable energy program how you appeal and participate overall in the program; appeal decisions and so forth. It's been updated to reflect RPS implementation. And to qualify for funding or RPS certification applicants have to satisfy the requirements in the overall guidebook as well as the applicable guidebook that's pertinent to them. For example, the RPS guidebook or the new account guidebook I just described.

A little sideline here, just a report on what's been happening in the new renewables account that we've had in place under the public goods charge funds since 1998. We had a few auctions in the past prior to the RPS being enacted. And we had 71 facilities that had some funding award agreements, or at least some preliminary funding award agreements, to get some of the PGC funds once they start generating. Almost two-thirds of those facilities are now online. Eight new facilities, 200 megawatts of renewable power came online in 2003. So that program has resulted so far of about 430 megawatts of new renewable power in California.

The integration cost issue, SB-1078, indicates that the PUC is going to develop rank ordering and selection of least cost/best fit resources as John mentioned. It's one of the key parts of the RPS. So that we can rank bids on a total cost basis.

Part of that is the indirect costs associated with transmission investments and integrating renewable resources. And as John mentioned, this decision in June of 2003, that decision built on some work the Energy Commission was doing and said the results of the phase one CEC integration study will reveal the integration impacts of renewable generation. And can act as a proxy for the integration cost effects of adding new resources until phase two results are available.

We do have phase one results available. The phase one results cover the integration costs as part of the total cost. It's divided up into the bid price, plus the transmission investments and remarketing costs and integration costs.

And this timeline for the phase one analysis shows you that we started at nearly a year ago, actually, in April of 2003. We developed a final report by December of last year. We had a workshop in February of this year to solicit final comment on that phase one report. And there were, currently, looking at the comments that we received there, and expecting to adopt that phase one report. And it results in findings on March 17th of this, you know, just a few weeks from now.

The tracking system, our term for it is the western renewable energy generation information system. Again, SB-1078 gave the Energy Commission the responsibility of developing an accounting system to verify compliance with the RPS, as well as insure that renewable energy output is counted once, only once, for the purpose of this RPS, or any other state, or for verifying retail product claims in this state or any other state.

So it's a fairly comprehensive mandate to track the claims about renewable power that's part of the RPS. We have been working extremely hard on this with a large group of stakeholders. It's intended to be a database of information, an analogy of like a banking system, so that people will have accounts generators and obligated entities in various places, such as in California, for the RPS. And certificates for renewable power can transfer from one account to the other as trade happens outside the system. They will transfer the certificates inside the system.

The geographic scope that we're planning in order to meet the full mandate that we have in the law is the entire Western Electricity Coordinating Council system. We're working closely with the Western Governors Association on this. We have regular weekly meetings at the staff level, regular meetings involving a variety of stakeholders developing the rules, and the data requirements. and the institutional requirements for this system.

Again, here's a timeline. We started this last April after developing a significant amount of background work and releasing a needs assessment report in December. We had a kickoff meeting in January down in San Diego. A lot of utility, other state regulatory government representatives, generator representatives came together and we started working with that stakeholder group, again on the actual rules, data requirements and institutional requirements of this system.

These three sort of parallel efforts are continuing, and we're expecting reports from these groups how to set the system up by March or April of this year. At which point we'll be going out with an RFP to develop a software for the system.

This gives you -- you cannot read this on the screen, but there were handouts in the back. It's a timeline that's been developed showing the CPUC and the CEC and IOU responsibilities or activities over the course of the next year as part of the RPS, leading to final approval of RPS solicitation contracts by December of this year, January of the following year.

For more information there's renewable portfolio standard integration cost; you can read this information on our website. And please feel free to go there if you're interested in all the details.

Thank you.

CHAIRMAN KEESE: Thank you. Is that the conclusion of the presentation?

MR. TUTT: That is the conclusion --

CHAIRMAN KEESE: I have a quick question because it seems to me that in the WSCC that we've been working on this since the day I got here seven years ago. This is a long-standing effort, isn't it, to come up with something?

MR. TUTT: There have been previous efforts to come up with something prior to the RPS, that is correct. As you might remember, when Commissioner Moore was here he was involved in a network to try to set up a tracking system with other states. There was some work with people up in Washington and Oregon.

This is a much more comprehensive aggressive effort to do the same thing that we started as part of the RPS.

CHAIRMAN KEESE: And are we getting pretty good collaboration with the western states?

MR. TUTT: We're getting excellent collaboration with the western states. The

Western Governors Association has been wonderful. Other states are interested in the process and working with us on the issue.

CHAIRMAN KEESE: Thank you. Any other questions up here? Any comments? Barbara.

ACTING DIRECTOR LLOYD: Thanks. My question probably goes to the PUC component. And it really is how much -- obviously we're talking about the initial actual procurement under the RPS model being done in maybe as late as September for this year.

What is going to be the timeline in future years now that this foundation has been laid? Because that seems like most of the year has passed and I just want to get a good understanding of how much of the groundwork laid here is going to carry over to future years.

MR. GALLOWAY: The bulk of it. Because the rules are in place this year, the future years, what remains to be done is to compute the market price reference. That's one of the key things that happens during the solicitation.

It's also depending on what the utilities need at that time. There could be a situation where we believe that the utilities have a need for RPS, particularly under the accelerated scenario. And we could direct them to do a solicitation at that time.

One of the key questions that's on the table is whether or not the solicitations happen simultaneously or whether they're staged. The Commission will address that issue this year. And then the utilities will be able to do a solicitation as needed.

CHAIRMAN KEESE: Thank you. Do we have any further comments from those who are involved in the renewables program? Commissioner comments at this time?

Thank you very much. We will then move, on time, to our fourth topic, to upgrade and expand the electricity transmission and distribution infrastructure, including presentations by the Cal-ISO, LADWP, Transmission Agency of Northern California and the Redding Electric Utility.

Ms. Doll, would you --

MS. DOLL: Yes, sir.

CHAIRMAN KEESE: -- do our introductions, please.

MS. DOLL: Good morning. What we have

in mind here is something a little bit different this morning. It's not going to be only a staff presentation. This is historic, maybe; I don't think there's a precedent, at least, for getting all of the people in the room that we have today to talk about the issue of transmission.

Of course, transmission is an important part of the energy action plan. It's an issue that it seems there's a lot of angst about, and maybe a lot of confusion about. And we're hoping that by at least getting everybody in one time to talk about it, maybe we can begin a useful dialogue.

But let me start with -- and can we turn those lights up over there, because we don't need a dark corner over here. And, by the way, I know there are a lot of people sort of hiding behind the post, but there are plenty of seats up front. So please feel free to come up here.

CHAIRMAN KEESE: Thank you, Pastor.

(Laughter.)

ACTING DIRECTOR LLOYD: Well, I think, you know, part of it is that they're concerned that their presence here today will somehow confer regulatory power back from you.

We have some representatives of the investor-owned utilities. I know Gary Schoonyan is here. Is there anyone here from SDG&E. Right here? Okay, good. Because one of the things I wanted to do was just quote, without permission, but it was in the newspaper.

Yesterday in The L.A. Times Deborah Reed, who is President and CFO of Sempra, -- and there's a copy of this in front of you -- was quoted as saying, in an interview, was quoted as saying, "There's also this whole issue of transmission and transmission siting. There's a huge need to address the expediency of getting transmission infrastructure built in this state." And she goes on to give an example during the first of how close we came to having a serious problem.

And I know we have PG&E, Les Guliasi, Ken Krausse are here. From the municipal utilities, and we're going to bring them up in a moment because we'd like to have everybody sitting up front, we have Jim Feider of both Redding and of the Transmission Agency of Northern California. And Jim's right back there. And with him is Maury Kruth, who wears several hats. But I think the hat today is Executive Director of TANC, as well.

And then John Schumann, who is Director of Power Systems Planning and Projects at LADWP, is standing right behind Robin (sic) Smutny-Jones from the ISO, so he's right there. And then both Jarry Jordan and Brett Barrow are here from SMUA, as well. So we have a good contingent from the municipal utilities, and a good contingent from the ISO, with Robin, Jim Detmers, who we're going to make speak. He's trying to put this off on Armando Perez this morning, but we're going to make him come up, as well, and Army.

So, one of the things that we wanted to do just by way of introduction is this is a summary of a table that I think was in a PUC document. We tried to simplify it, and Tom Flynn has done that. I'm grateful to him and grateful to the CEC for the making of it. But, it's over here, and there are handouts, as well.

You know, how does this work; essentially what are the roles of each of the parties who are going to talk here this morning. And this is a very very simplistic level. But the IOUs are also serving as what are called participating transmission owners, PTOs, relative to the ISO. And maybe they can explain to us why they come up with different terminology.

And they develop and propose their projects to the ISO. And then, of course, they design and construct projects that have gone through the ISO and the PUC approval process.

They also participate in the regional planning process. You see a box up there which looks fairly simple, but it really also involves, as we've already heard about this morning, the Western Electricity Coordinating Council; some rules and guidelines that are put forth from NERC, the National Electric Reliability Council, and then, of course, FERC.

So, that regional planning process is very important. And something that everyone in this room participates in.

The ISO does the transmission -- the grid planning process there, determination of need, selection of preferred alternatives. They're looking at reliability and at cost effectiveness.

And this cost effectiveness issue is something you've already heard about because, as you know, the ISO is currently working on a model, an economic model that will be able to feed into the PUC's review of future transmission projects.

The same process, I think we're going to hear, and I hope we can get confirmation of this, essentially happens with the municipal utilities. They are part of the regional planning process in coordination with the ISO. They don't go to the PUC for regulatory approval; they go to their own local regulatory bodies.

And then we're going to hear from the -- Barbara's going to make a brief presentation in a second. But another group of parties that are not on the board here, but I think are going to be represented today.

There's a project being proposed called the TransBay Cable project in San Francisco. And the company that is proposing to develop it is Brown Babcock, and I think that one of their representatives will be here today. This is a different model, maybe a little bit more like the Path 15 model, and could be interesting.

But the other article that I gave you is from New York where apparently, yet these are just both from yesterday which is why I put them together, but there's a group of investors looking to do a similar kind of thing and build a transmission line in New York privately. And they were going to do an auction for space on the line, but they withdrew it. And suggested that they have been scooped by the distressed energy market conditions and the potential financial commitment.

So, I think it would be interesting if some of these kinds of issues could come up today. We're trying to get at what works; what doesn't work. What do we have control over. Is there consensus here about what are the most important projects that the state needs. I think we may find that there is. And what's the number one problem or shortcoming with the existing process that needs to be fixed.

At the last joint meeting Commissioner Kennedy noted at one point, and I'm not reading from the transcript, just from my own notes, she said we're dancing around the issue; we're clouded by turf.

But she asked two questions. One, can we agree on a need for statewide planning. And can we agree on key changes to fix the problem. When Chair McPeak asked Director Vial and me to go out and talk to people, many of them in this room, about the transmission issue, I thought we were going to find that planning was the big problem.

And I'm just going to lay out here for the beginning of the discussion that that we've heard from many of the people in this room is that that planning is not the problem. So let's see how that goes, as we hear people this morning.

I'll turn it over to Barbara, who's going to give an overview of what the PUC is doing and while that's happening maybe we can get everybody else up to the tables up here.

MS. HALE: Hi, everyone; I'm Barbara Hale; I'm Director of Strategic Planning at the California Public Utilities Commission. And I just wanted to give a brief overview of what sort of investments we've seen our investor-owned utilities make on transmission since 1996. And to describe a little bit about what sort of projects we've seen, and what the PUC process is about.

Kerry Hattevik from my staff will then describe some of the more active efforts at reform that we have underway at the PUC. And then Don Kondoleon from the Energy Commission will describe a little bit about the Energy Commission's active proceedings.

So what you see here first is that California investor-owned utilities have been making steady investments in transmission in California.

CHAIRMAN KEESE: Can we dim the lights a little over in that corner again, please.

MS. HALE: $280 million on average for a total of $1.981 billion invested in electric transmission lines and facilities in 2003 dollars.

We've completed, through the investor-owned utilities, 124 transmission projects that have added 13,000 megawatts to the investor-owned utilities transmission system. We've done that through new lines, as well as replacement of existing lines. And there's a couple of examples here. The TriValley project which is helping PG&E achieve the reliability for its growth area there, and the northeast San Jose project.

The utilities have received or have applied for permission to build over 140 other projects. Many of the transmission projects that the Public Utilities Commission sees are not, they're not transparent to the rest of the public. They're not what you see in the newspaper. But they're the real meat-and-potatoes of keeping the investor-owned utilities transmission grids reliable.

Right now before us we have a couple of projects that are really key for reliability purposes. The Jefferson-Martin transmission line that you see on the bottom of the screen here will help avoid a repeat of the 12/98 blackout that San Francisco experienced. That comes out of a process that had a lot of involvement by various stakeholders that the ISO really championed in trying to make sure we had the right transmission solution to avoid that sort of a repeat.

PG&E, coming out of that process PG&E filed for a CPCN for this transmission line. And it sort of captures the sorts of controversies the Public Utilities Commission addresses in the CPCN process. It's a transmission line that's coming through a very populated corridor where there aren't people. There are endangered species, and the Public Utilities Commission, through the CEQA process, is grappling with all those issues as we try to address the reliability issues that that project will help us address.

We also see on the horizon further projects in the planning stages that haven't actually been filed at the PUC, but that we're keeping a sharp eye on.

And, yes, you know, the PUC doesn't always say yes to transmission project upgrades. It's important for us to acknowledge that, and to point out that there are times when the agencies, the PUC, the Energy Commission, the ISO, you know, we can acknowledge that we've had disagreements. And those seem to be the ones that make it in the newspaper, not the ones where we've come to agreement or moved forward with approvals.

I think it's important to keep in context what transmission improvements mean for the ratepayers. It's a big bang for the buck, you know. A very small portion of energy bills are attributable to actual transmission costs.

And then the Public Utilities Commission has also had a strong hand in interconnecting some of the projects, the generation projects, numbering 32. The High Desert interconnection is an example. We're also trying to work closely with the Energy Commission on making sure we have the transmission upgrades necessary to bring our renewables potential through the load-serving entities to California customers. The Tehachapi project is a good example of that. And you've heard a little bit about those efforts already from our renewables collaborative group.

So, at the PUC we've got a couple active proceedings. I'm going to ask Kerry Hattevik to come up to give you a brief overview on now. And then she'll be followed by Don Kondoleon from the Energy Commission.

Kerry.

MS. HATTEVIK: Hi, my name is Kerry Hattevik. I work for Barbara in the Division of Strategic Planning. I actually became involved in transmission with, you know, a very fresh perspective because I didn't know a lot about it before about a year ago. My work has really been a fallout of the energy action plan where I've been asked to look at the various processes across the state and make recommendations for making it better. So I really did come to it with a fresh perspective. And this is sort of what I've learned and what the outcome of our efforts here have been.

The Commission has three prominent proceedings on transmission. One is our transmission OII; that's a fallout of AB-970.

That is a seven- or eight-phase proceeding. And Tehachapi is the seventh or eighth phase. So we've been at it in the transmission OII for awhile.

The ongoing efforts in that proceeding at the moment are predominately looking at a better economic model for determining whether transmission is needed. That is a very big undertaking that we're hoping to finish by the end of the year.

The other one that's ongoing in that proceeding right now is the Tehachapi project, which is transmission to the Tehachapi wind area. And that decision is to be coming up in the next few weeks is my understanding.

The other one is sort of a result of the report I did as an outcome of the energy action plan. That's our transmission OIR. That was voted out on January 22nd of this year, and it proposes changes to the Commission's current transmission planning process to streamline it and work more closely with the ISO.

Essentially the bottomline is that we're really looking to streamline the process and work with each agency's expertise. The ISO clearly has expertise in transmission, engineering, reliability, all of that. And we have a lot of expertise and we're very involved on the cost side, as well as working with FERC and integrating it into a comprehensive plan and coordinating it with our procurement proceeding.

So that's sort of the perspective that we had in putting the OIR forward was really to work with the core competencies here and try to make a transmission planning process that makes sense and is good.

Barbara already talked about Jefferson-Martin and I think Mission Miguel is -- that is in the CEQA process as we speak. And I think decision is expected in the summertime or late summer. That's a transmission line in the southern part of the state. It's getting a lot of attention at the moment because there's a lot of congestion there, plaguing Jim Daly, I believe. We're working on it and we understand that that is a very active part of the state as far as transmission.

The report I did was appended to the OIR that was voted on on January 22nd. It essentially, you know, being in the Division of

Strategic Planning is given as sort of a unique position in looking at transmission planning because I was able to look at our procurement process as well as integrate it into the federal and the market-design issues and transmission.

Transmission really is the linchpin of all of those state and federal policy issues. And sort of in the area that we've worked in, strategic planning, was that we were able to get sort of a bird's eye view of how all these pieces are fitting together.

The report came out with five, four or five key recommendations on where we can make it better. The one is that we need to integrate planning better. We are, through our procurement proceeding, have been working to work with the utilities on their procurement practices. And in there we're looking at the best way to meet need, whether that's demand response, energy efficiency, new contracts, new generation, transmission, what-have-you. That's a place where we're looking at a comprehensive way to meet need.

We've lacked that . That's been a problem, you know, the landscape that we see today is where generators, a lot of them locating even outside the state, have a bearing on our transmission system. And that link between the transmission generation site has really been lost. And we're trying to bring it back, both through the comprehensive plan starting with the utilities, but also through a better coordination on the state and federal policymaking issues.

The planning process is balkanized. One of the key recommendations in the report is that RMR be integrated into the comprehensive planning process. RMR is just a good example. There are other areas, but RMR, reliability must run, contracts that are needed for local reliability needs, where there's not enough transmission or you have generation or load pocket that's needed to support the transmission system, those contracts are signed yearly. And it is somewhat of a balkanization of the transmission planning process.

And really what the last procurement decision on January 22nd did was suggested on an ongoing basis utilities roll in local reliability needs to their long-term needs so that you get at that better. What's the best way to meet those local needs. Is it more transmission? Is it local generation? What is it that you need there? More energy efficiency, more demand response.

But the balkanization of the system at the moment is both costly and it's just plain inefficient.

The key recommendation of the report and the one that the OIR acts on is the redundancies in the existing transmission planning process. As you'll see from the next slide, and you could also see from Laura's, transmission planning really starts with the PTOs, the participating transmission owners and the ISO.

Traditionally the Commission has not been very involved until the application by the utilities ends up on our doorstep. That's been a problem. People don't like it when they've been working on a project for two years, and then people, you know, two years down the line start getting involved in it.

So, the redundancies are predominately where the ISO looks, determines whether a project is needed; they go through a process for doing that. They do high level environmental; they do various scenarios; they have public participation hearings; they have alternatives. And they determine whether a project is needed either for economic reasons or reliability.

When the utility files an application at the Commission for a permit for that project, we do it all again essentially. We do both an economic and a reliability need assessment. And it's frustrating because people don't want to do it again. And they're saying why can't you just work closely to get it done. And that's really what we're trying to do with the OIR.

The other thing that came out of a decision about two years ago in our transmission OII, in looking whether additional transmission is needed to the southwest, is that traditional methodologies for assessing the economics of whether a project is needed for economic reasons or just plain inadequate in the market design, as it is. The market is just too dynamic to use traditional methods for assessing the economics. And we recognize that we need a more dynamic way of getting at those economics.

The ISO has been working to develop that methodology. They've been doing that for over two years. And it's hard. It's a big undertaking. But they are going to submit their model to the

Commission in June and we're going to have a public process to look at it. But that will be a really key element in looking at economic transmission projects going forward so that we have a model that will get it, you know, is this worth the dollars.

And, again, this official coordination between state and federal policy. That includes deliverability requirement, capacity rules, interconnection rules and transmission pricing. All of those are where you see the federal and state side come together.

I just wanted to point out one other thing before I move to the next slide. When I started looking at this assignment coming out of the energy action plan I really started looking at the PUC's process and how we do it, and how we can make it better. And what I quickly found was it's not all about us. It really is about the munis and the ISO and outside the state, the western region.

A lot of the generation that's coming online to serve California is not in California. Doesn't go through our siting process, but it impacts all of our transmission and everything else. So it really needs to be a comprehensive approach that both works on the federal and the state side to make sure that those policies gel.

And we're really working hard to make that happen.

This is the more complex version of Laura's; this is the current transmission planning process. If it looks complicated that's because it is. I kind of talked about the fact that the PTOs, it really starts with the ISO and then it funnels into the PUC process, and then it goes to FERC for rate recovery.

So, let me see. I think I've talked mostly about what the proposed changes to transmission assessment are. What we want to do, or I at least started with it, is that we want the transmission planning process to start in a comprehensive approach at the Commission through the utilities long-term plans.

In there the utilities will come in and say, okay, I have need in San Diego. I'm going to meet it by this much energy efficiency, this much demand response, this much transmission, this much generation. That will be a very high level review of the transmission component. That transmission component is really going to be analyzed in the ISO's process.

The ISO will then, once the utility takes it to them, assess where their project is needed, either for economic or reliability reasons. And to the extent that we've worked through our transmission OII to get an agreed-upon way to assess those economics and get a reliability standard, we are proposing to defer to the ISO's determination of need. That is, we're not going to re-do it. We're not going to start the need assessment all over again. We're going to accept their findings.

When the utilities come to us for a CPCN application we're going to accept ISO's fillings; validate those filings; and then conduct CEQA. So nothing in this process is changing the CEQA process at all.

In fact, when I was working with all the entities involved in transmission and trying to figure out what the problem was, almost everybody mentioned that this redundant need assessment was a problem. Nobody, not one person said that CEQA was a problem. And CEQA is not being affected in this process at all.

The other issue is deliverability and capacity resources. That is being dealt with in the PUC's procurement proceeding. In the transmission report that I did, I really said that deliverability is one of the key things that will link the transmission generation side. It will also -- it also works within the market design. It's also sorely lacking at the moment.

Deliverability is, I think, -- well, not from the ISO's perspective, but I think in terms of the way we thought about it, has been not addressed as much as it has been, or should have been. The ISO's proposed deliverability standard for new generators and their generation interconnection rule, we've supported that. That means that new generators that interconnect to the grid, that power has to be deliverable; there's some standard they have to meet. That's an improvement.

What we need to do now on the state's side is make sure that when the utilities go out to contract for that capacity resources, those resources are deliverable to load where they're needed. And we don't have that now.

And I should also mention the

deliverability issue is an issue currently where there's a significant amount of contracted power that's actually not deliverable to load, and it plagues the ISO constantly that they need to, in real time, make up for that power that's not deliverable to load.

This is our proposed process where it starts with the Commission procurement proceeding, with an economic methodology, filters into the ISO process, and then comes back to us and we do CEQA, validate the need assessment, and move on.

The transmission OII is where we're currently looking at the economic methodology. The hardest thing that we're going to have to grapple with there, that the ISO is grappling with in developing the methodology, is market power. How do you model bidding behavior, potential bidding behavior and market power. It's a challenge; it's going to be hard. But, considering the fact that a lot of the transmission projects we're looking at, particularly because a lot of the generation is in the southwest in transmission-constrained areas, those are economic projects and we're going to need a better model to look at them.

I should note, though, that in developing this economic methodology to filter into our revised process the economic methodology for a test is going to be used on a prior project. The reason for that is that we didn't want to apply it to a, you know, for example Edison has told us that they want to file Devers-Palo Verde. We didn't want apply it to a new project because as we're looking to assess, you know, a new way of doing this we didn't want to hold up any transmission projects.

So it was very intentional that we're using, you know, a past project description; we're using Path 26, because in the meantime while we're assessing this, we don't want to hold up anything.

And ISO's currently conducting workshops on the methodology. They're really fun. And they're going to submit their methodology to the Commission in June. And we're looking at a decision at the end of the year.

In parallel to the OII process for developing the economic methodology, the OIR is ongoing. That is where we proposed changes to our general order 131D, which tells us how to do our transmission process, that says to the extent the

ISO uses an agreed-upon methodology, agreed-upon reliability standard. We're not going to revisit the question of need.

ISO filed comments last week; others are going to file comments soon. And we have put that to make a decision on that within eight months. Now, that's running parallel to the OII. And what the OIR is saying, here's what we're going to do once we have this new methodology; here's our plan; here's how we're going to make it better.

The OII is running in parallel and, like I said, I don't think the methodology is going to be done probably till the end of the year.

Be able to answer questions that anybody --

MS. HALE: Let's go ahead, before we take questions, let's go ahead and give Don Kondoleon an opportunity to talk a little bit about the CEC proceedings that are actively under way. Don, do you want to come on up?

MR. KONDOLEON: Sure. Thank you, Barbara. Thank you for providing me the opportunity to speak today. And it's great to see so many people here, so many familiar faces. We don't usually have them all here at the same time.

Let me speak just briefly about the staff's activities with the 2004 IEPR update. Staff's goals for the 2004 IEPR update are to continue the process of implementing a fully collaborative transmission assessment in the IEPR by building on the ISO's transmission planning process.

We began the 2004 update actually in November of 2003 with a Committee workshop that identified the need to examine so-called strategic benefits when assessing the value of proposed transmission facility.

The principal presentation at the workshop provided by the CERTS team highlighted the fact that the current evaluation process undervalues the benefits provided by many of the proposed transmission projects.

And so that is a central theme that we'll talk about here, and what we're trying to capture in 2004.

In 2004 staff's going to collaborate with participants to do a number of things. First, we're going to develop demand and supply assumptions and state objectives for use in the ISO planning process.

Second, we will investigate ways to examine in the ISO transmission planning process non-wires alternative to projects. We're going to continue to participate in the development of the state-adopted methodologies, as just mentioned, for assessing the benefits of transmission projects proposed for economic expansion of the grid.

We're going to complete a corridor viability study to determine the expansion potential for certain electric transmission corridors in California. We're going to continue to develop this notion of the use of so-called strategic benefits in assessing transmission projects.

And finally we're going to prepare a staff assessment on the consequences of not going forward in a timely way with the near-term projects identified by the ISO in their transmission planning process.

The IEPR process will include a number of Committee workshops, and we've got those tentatively scheduled for April, May and June. And you will be able to follow those either through our website, or if you're on our mailing list.

Staff is going to complete a transmission white paper that will basically document all of our activities throughout the 2004 process. And we will be releasing that document in July of this year. We are anticipating holding Committee hearings probably in August and September. And then the release of the final IEPR update is scheduled for November 1, with the Commission likely to adopt that document sometime in middle to late October.

So, in a nutshell, that's the staff's activities. Are there any questions? Or we can hold them for later, Bob?

MR. THERKELSEN: One last comment. Thank you, Don, for talking about the IEPR update activities. But one last comment.

The IEPR, the Integrated Energy Policy Report, established by the Legislature is basically a foundation document. And one of the things in the establishing the energy action plan, the three agencies agreed, was that was going to be the analytical and information basis of the policy actions and the implementation actions that we took.

Transmission, as Laura alluded to earlier, has been one of the areas that probably has been more challenging for the agencies in terms of getting their focus together on. And I think one of the things we're trying to do -- the first IEPR was obviously adopted this last fall. One of the things we're trying to do for the 2005 IEPR document is to make sure that when we're considering our assessment of not only demand, but resources, that those assessment of resources look at integrating both generation and transmission.

So that that document that's released in '05 and is going to be used by the PUC, in terms of their subsequent procurement process, reflects not only the generation needs of the state, but also the transmission, demand reduction, renewables and other needs, as well.

So that's going to be an interesting challenge to work together, with agencies, and also with the stakeholders in terms of making that entire process work.

And so we look forward to your participation in helping us accomplish that.

CHAIRMAN KEESE: Thank you, Laura.

ACTING CHAIRWOMAN McPEAK: I have some

questions.

CHAIRMAN KEESE: We'll do two things here, in just a moment while you're getting everybody to come forward. Commissioner Kennedy has joined us. Welcome. And Ms. McPeak has a question.

ACTING CHAIRWOMAN McPEAK: I have a couple. First of all, it looks like very good progress in trying to integrate and simplify or streamline, to the extent possible, the process. And so I want to congratulate you for doing that, particularly being able to rely on the ISO's certification of need.

I did want to probe an aspect of the report a little bit, and that was the comment that nobody saw the California Environmental Quality Act review and compliance as an issue in going through the work. And I want to hasten to say that the energy action plan and all of the reports that I've seen from many of the agencies are totally committed to high environmental standards and protection of the environment.

But it does seem to me that CEQA compliance, project-by-project, is a problem. And I, at least, want to push back on that. If I've, you know, tried to catch up and learn something from all the debate here, and particularly what Director Geesman keeps hitting us over the head with is the interrelationship of transmission to other sources.

And therefore there is actually a relationship of taking of a package of actions together that could be much more environmentally desirable than dealing with them independently. And that's part of what I've seen in the energy action plan. And actually have thought that perhaps we should look at that in and of itself as a project, which would help streamline proceedings immensely.

But the other aspect I wanted just to talk about is the transmission component alone. Because having a transmission system and looking at how it works efficiently, taking into account location of renewables, and doing an environmental assessment that is evaluating the result of a transmission system and not a particular path, I think, would be maybe a lot more desirable, and actually have greater efficiencies in terms of reviews that are ultimately done by the PUC.

So, could someone comment on that? I'd

like to, you know, if we actually had, for example, a transmission plan that gets pulled together, as Mr. Therkelsen said, into the IEPR, is that is -- PR, I never get these initials right.

MR. THERKELSEN: IEPR.

ACTING CHAIRWOMAN McPEAK: Okay, IEPR, and had a plan for which we then had a document that we wouldn't have to duplicate the EIRs over and over again.

MS. HALE: Barbara Hale from the PUC. I think what I'm hearing you say, Director McPeak, is you're using project in the CEQA type of term where you would do -- and I think you're suggesting CEQA -- are you suggesting CEQA as on the IEPR as a program type of project? I'm not sure --

ACTING CHAIRWOMAN McPEAK: I actually raised that as a possibility also on the energy action plan. But set that aside for the moment. What I am looking at is now asking a transmission plan which truly has several components to it. And if that's going to be in the Integrated Energy Resource Plan Report of 2005, could there not be an environmental review on that, as a integrated set of components?

MS. HALE: Well, to the extent that's a question about the IEPR, I'll defer to the Energy Commission. But think about in terms of what we would then have to do with it, if a transmission project --

ACTING CHAIRWOMAN McPEAK: Yeah, do you have to keep doing an EIR on every proposal?

MS. HALE: Well, we would have to comply with CEQA with respect to the specific project that comes out of the program, what I think you're describing as like a program EIR. If there was like a general plan kind of a document --

ACTING CHAIRWOMAN McPEAK: Um-hum, um-hum.

MS. HALE: -- a CEQA document that came out of the IEPR, then we would still have to make sure that specific projects and specific routes of transmission development were adequately addressed under CEQA.

So it probably would be a -- I'm guessing it would be a smaller scale effort, but it would have to address the specific ground, the specific footprint of the project, whereas what

I'm understanding you describe as a program EIR of the IEPR would be more general.

ACTING CHAIRWOMAN McPEAK: Um-hum.

CHAIRMAN KEESE: Mr. Therkelsen.

MR. THERKELSEN: Actually I'll defer to Commissioner Geesman first, and then I'll make my comment after that.

CHAIRMAN KEESE: All right.

COMMISSIONER GEESMAN: Well, I certainly congratulate your Commission for the candor in which you've acknowledged the serious deficiencies about the way we've been doing this in the past. I think the state needs to take a much more proactive approach than your proposal. I think it gets at some of the issues that Secretary McPeak raises.

We need to move more of these decisions into a planning process and fewer of them into the gladiatorial arena that the CPCN process represents. I don't think the Perry Masons and Clarence Darrows and Johnnie Cochrans that inhabit the CPCN process really provide much value added in meeting the state's needs.

And I think that we can accomplish a great deal more if we proactively attempt to establish the need for particular projects, identify corridors where projects are necessary, address the CEQA issues up front, and begin rolling out permits for facilities that I think all of us acknowledge are desperately needed.

I'm glad that Deborah Reed's interview was distributed today because I think it's slowly becoming clear how close we came to blacking out San Diego during the fires last fall. And I think had that happened it would have made the fiasco we went through with Path 15 pale by comparison.

I strongly encourage you in your efforts, and I don't think that it needs to be seen as a question of turf. Wherever state government decides that these responsibilities should reside, they need to be much more closely integrated. And I would hope taken out of the litigative context and put more into a planning process.

CHAIRMAN KEESE: Mr. Sweeney.

DR. SWEENEY: This may -- you may comment on it, maybe somebody else will comment on this more later, at which time tell me to defer the question. But in developing an economic model, which I commend. I understand it will deal with the risk of the uncertainty of transmission planning. Will this also include some valuation of environmental consequences of the alternative routes? That is, as one develops an economic model you could develop a narrowly economic model that simply looks at risks and dollar costs, or more broadly economic model that integrates into this planning process in the optimization environmental consequences of the action, which is what overall strategy is being taken here.

MS. HATTEVIK: Well, I think the ISO could talk in detail about their model probably better than I can. But, my understanding of the model is it really is looking at the various routes and options and the generation versus transmission tradeoffs, as well as looking at the full network in the west. And looking at the economics of that.

Just to be clear, on the CPCN process that we have at the Commission, we have one, a need determination, and two, a CEQA evaluation. The need determination says is this project needed. Answer yes or no. If it's yes, the CEQA process, if it's warranted or it's triggered says, okay, now that we need that how do we make the most environmentally sensitive project, or adequate project there.

I don't know that in that economic model they're going to be looking at the environmental components, per se, but maybe, Armi, can you speak to that?

CHAIRMAN KEESE: If that's okay with you, why don't we go to the ISO for your presentation.

MR. THERKELSEN: Bill, may I respond real quickly to Sunne's question?

CHAIRMAN KEESE: Mr. Therkelsen.

MR. THERKELSEN: One of the things she asked for was whether we were going to be doing some moving the environmental work, if you will, up in the planning process. And as Mr. Kondoleon mentioned, one of the things we're doing in the 2004 update, and this basically was done at the request of the ISO in working with them, is looking at corridors and looking at, if you will, fatal flaws associated with environmental corridors so those environmental considerations can be brought out early in the planning process; not going down to the CEQA level of detail, but again, at a higher level of detail so we can bring that environmental attribute assessment, if you will, into play at the same time that economic assessment would be available.

CHAIRMAN KEESE: Thank you. Mr. Perez.

MR. PEREZ: Hi. I'm Armi Perez, Director of Grid Planning for the California ISO. And it's a real pleasure to be here with you today. I think this is the first time I actually made a presentation to any of the Commissions. So, let's get going.

I am one of those few folks that is blessed; I get to work with three different agencies. Let me describe briefly what we do with them.

The first one is FERC. And we sort of get our planning authority from FERC. FERC kind of looks at us to make the determination of need, so hopefully when a utility files for rate recovery at FERC they look to see whether, in fact, the ISO has approved the project or not as being necessary and cost effective.

And I think after the little incident back east FERC was going to become a little bit more powerful. I think we will have some reliability with the legislation that will be mandated and it will be enforcement and penalties if we don't get there.

For the CPUC I think we provide input to the various issues concerning transmission policy. We spend quite a bit of time preparing testimony and giving testimony at the CPUC hearings. We provide assessment of new generation, deliverability. And we do make a determination of project need whether it's reliability or economics.

There has been a lot of discussion, people not understanding the difference between reliability projects and economic projects. So let me just spend a second doing that. I see Mr. Peevey shaking his head yes.

ACTING CHAIRWOMAN McPEAK: Is that because he does or does not understand?

MR. PEREZ: I think he wants the explanation, so let's go there. A reliability problem comes about because let's say I run a 2006 case and I take a line out. And when I take the line out I have a violation to the reliability criteria. That forces me to find a solution so there's no problem with that criteria being violated.

So we will either do a project or do something else to make sure that criteria violation goes away. The big point here is I am forced to do something.

An economic project is a little different. The simplest economic project that I can come up with is if I have a line that has very heavy losses and I decide to reconductor the line because the cost of reconductoring the line will more than offset the cost of the losses, that project is economic. Do I need to do it? No. Is it optional? Yes. Should I do it? Yes. It benefits the ratepayers. That's the simplest way to get the two separated.

Okay. The CPUC does for us the siting process and the authorization of future resources for the jurisdiction of utilities.

With the CEC we provide written and verbal testimony again when they're looking at generation projects going through the licensing project. And we do provide information to them on transmission requirements for potential future generation. We get from them the load forecast, the generation retirement information and the new generation information, including the renewables part.

Now, let me change horses a little bit. We have been morphing ourselves quite a bit since I started to work at the ISO in 1987. At that time, '97, '98, we were doing the five-year plans for the utilities; we were doing the RMR studies; we were doing generation interconnections. The criteria that we were using at that time was basically a deterministic criteria. It had nothing to do with probablistic. It says if this happens, you do this. It didn't take into account what was the problem if this happening.

And we were only working on reliability at that time. We had no way of doing economic studies at that time.

Since that time in 2004 we're doing the five-year plans. We continue to do the RMR studies but this year we're going to take a lot of effort to redo or remap the RMR, the process, the criteria, everything is going to be relooked at through a stakeholder process.

We continue to do generation interconnections and we had a FERC filing last year, last month, I'm sorry. But now we're doing economic studies based on London economics, which, as Kerry mentioned, has taken us about two years. And we're going to be filing this with the CPUC in June.

There is a little bit of environmental assessment on this economic analysis. It basically weights the different transmission line routings depending on what the environmental impact of the line may be. So that's as far as it goes.

We're moving into probablistic planning. As a matter of fact we just had a large meeting in San Diego where we talked about probablistic for about two days. We're deeply into subregional planning, not the SSG-WI type, although we're involved with SSG-WI, but we have a process that started with the southwest called STEP; has been extremely successful and I'm very happy with that. And last month we started the same process with the northwest, which is called NTAC, N-T-A-C. And we're slowly getting that group to do about the same -- hopefully we'll do the same thing that STEP did.

And, of course, we're going to be doing deliverability studies. We just obtained a program from PTI called MUST, which is the tool that we're going to be using to do that.

So what do we do for the purposes of the ISO is the interconnection generation or load, protecting or enhancing reliability, insuring efficient use of the grid, enhancing operating flexibility, reducing or eliminating congestion where economic. The key there is where economic. We're never going to take all the congestion away, only that that makes sense to do so. And also the main thing that I look at is the ratepayers benefit.

This is a beautiful slide and I put it in color for you because this came out of the SSG-WI group, and it has a lot of interesting information on it. Each one of the squares has three lines in it. A blue line that signifies transfer capability in one direction; the red line means transfer capability in the other direction; and the one in the middle means the zero axis.

This program was run using a production cost simulation but telling the production cost simulation that all transmission line has zero impedance. In other words, there was no transmission limitation when you ran it.

If you look at the most obvious case in

here, which is the line -- the graph between Alberta and British Columbia you can see those folks need transmission up there badly. But there's none planned. And if you look at east of the Colorado River you can see the same is happening. There's a lot of yellow area on the other side of the transmission limits saying that it wants to flow but it can't flow.

This graph is for you to look at it and enjoy.

(Laughter.)

MR. PEREZ: They asked me about give you a little idea of possible items under construction. As we know, we talked about the Jefferson-Martin, which is the purple line in here. We have another line between Martin and Hunter's Point, which is the green line; it's a 115 kV cable that's badly needed also in the Bay Area.

Everybody knows about Path 15; that's under construction; should be in operation by December of this year. There is the Metcalf to Moss Landing reconductoring that should happen soon. Regarding renewables and the development of the Tehachapi there's a possibility that we may look at time the San Diego -- I'm sorry, the PG&E system and the Edison system in the Big Creek area. That's in the north.

In the south we have, of course, the Mission upgrades; that is in front of the PUC right now. And if I have to say one thing, it's don't take any longer than you need to. The congestion out there is very very bad. The ratepayers are suffering. We need that approved quickly.

UNIDENTIFIED SPEAKER: I think the fire is burning --

MR. PEREZ: I sincerely hope so. If you need more fuel I got some outside.

(Laughter.)

MR. PEREZ: We are thinking that we're going to need a 500 kV line probably from Imperial Valley into the San Diego area as a reliability project. And a Palo Verde-Devers number two probably will be needed to base on economics. We're looking at the study right now.

Now, I'm a very friendly guy, as you can tell. I don't want to make anybody mad, but I've been asked many many times if you had your way of doing it, how would you do it. And this one man's answer to this, okay.

So let me explain what you got here. There's a black box in the center. In that black box is basically the processes of the ISO. One will be an economic methodology that has been CPUC review and probably approved, and a reliability criteria that was filed with them just recently. And that's the criteria that we use for deliverability, operational needs, both power programs and RMR. Although the RMRs use a different criteria; that was also filed.

I call the black box something that I just crank it. Something goes in, I crank it -- something comes out. The inputs are the load forecast and the generation forecast that comes from the CEC. But not the way they're doing it now. I want buss by buss load forecast for the next ten years. They have to work with the PTOs to get there. That I can take directly into my programs and use it. I also want generation forecasts, buss by buss, for the next ten years.

And then from the CPUC I want the resource adequacy decisions and the renewable generation requirements decisions, and that goes into that process. That eliminates the fact that if I go anyplace and they tell me you don't need that project because the load forecast is wrong, I send them to the CEC. Their problem, not mine.

Forget the two arrows there for a second. Out of my black box only comes out transmission projects. Why? Because that's all I can do. I can only get you transmission projects.

A lot of people ask me, did you consider resource adequacy -- I'm sorry, not resource -- did you consider demand side and did you consider generation alternatives to transmission projects. Well, the demand side, you know, whatever happens with distributed generation, whatever happens with demand programs that tend to reduce the load should be into the load forecast that the CEC has just given me. So I should not have to worry about it.

The other one is can I put a generator someplace to eliminate the line. The answer is I cannot, generators located at location A. If you tell them you want to locate on location B to stop the transmission line from being built, they want dollars. And I don't have the dollars, and I don't have FERC approval for generation -- for transmission to be put on transmission rates. So, somebody has to fix that part of the problem for me.

Summary. We work close with FERC, CPUC and CEC. We think we have a very good comprehensive grid planning process that coordinates with the entire grid through SSG-WI and through WECC. The data and the assumptions come from a variety of sources including the CPUC, the CEC, the WECC and SSG-WI. And the reliability standards that we use are basically WECC, NERC and a little bit of ISO associated with local area problems and associated with nuclear regulatory requirements. And that's about it. Thank you.

CHAIRMAN KEESE: Thank you very much.

ACTING CHAIRWOMAN McPEAK: Mr. Chairman, if I might, actually I thought your schematic of the partnership was quite instructive. Are you able to go back just a little bit to that?

MR. PEREZ: I think so.

ACTING CHAIRWOMAN McPEAK: The comment you made about the debate that sometimes happens when you propose a transmission project and folks ask you, did you consider the alternatives, is in fact the debate we're trying to avoid by having the energy action plan and the loading order.

Such that, as you said, well, we would rely on the load forecast from the Energy Commission.

And implicit in that continuous process of looking at load forecast is not only demand, but the supply response, which is the loading order.

And so often in resource issues we get into false debates I used to characterize in the water world as conservation versus construction, the fact is we needed both. We sometimes get into conservation demand management or construction and energy. We need both.

We sometimes talk about market-based solutions and, you know, the dynamic pricing, et cetera, versus transmission. We need all of it.

What we're trying to do in this process of collaboration and moving to partnering, as you have up there, is to have embedded in a plan the values that we want to bring to our energy management.

And optimizing the load management, the conservation, the efficiency so that we know that at least we have, with the technology available to us, exhausted that. That we have, with the methodology that's being done now, developed by the ISO on tradeoffs between generation and transmission, and then looking at a transmission program, we will have taken into account a lot of those factors that sometimes at the end of a project evaluation get debated.

So I appreciate very much how you have expressed this here, and also the fact that the up-front work we are doing is intended to avoid too much controversy at the end of the process.

MR. PEREZ: Thank you; appreciate it.

CHAIRMAN KEESE: Thank you. Commissioner Peevey.

PRESIDENT PEEVEY: Well, if I understood you correctly, sticking on the same slide here, is that it would be particularly useful to the ISO if the Energy Commission's demand forecast, generation forecast -- let's just take the load forecast, was frankly more granular.

MR. PEREZ: Yes.

PRESIDENT PEEVEY: Right?

MR. PEREZ: Yes.

PRESIDENT PEEVEY: More detailed, and therefore more meaningful.

MR. PEREZ: If you give me a --

PRESIDENT PEEVEY: And a good bit of

time could be spent on that by the Energy Commission profitably?

MR. PEREZ: That's my belief.

PRESIDENT PEEVEY: Thank you.

CHAIRMAN KEESE: Thank you. Well, if we can take -- Director Vial.

DIRECTOR VIAL: Just add to what Mr. Peevey said, what we do know is that transmission planning and building a project takes a long time compared to building a plant. And one of the problems that we've had, as well, we've identified many transmission areas, congestion areas, we've always been very slow in getting that project upfront and really focus on it.

And it seems to me that in your schematic up there what is most critical is that the analytical work that is done by the CEC, that it come in as very strong baseline work in the integration of transmission planning with procurement. And that's in that first box of the PUC.

That needs to be done, and there needs to be a very early identification of these transmission products, because as Jim Detmers points out, that if we don't do this and get these projects built when they're needed, we just pay and pay and pay. And he can give us figure after figure on how costly it is to do that.

So it seems to me that in this planning process that we have now launched with the IEP, that the Energy Commission, with its requirements, the IEPR process, really is in a position to be very proactive in that early assessment and relationship of transmission planning to procurement. Recognizing that we have a national policy, a FERC policy, is to promote open access approaching to common carriage, promoting robust wholesale markets.

And that this means that we need to really get that planning process for transmission upfront with transmission. And I think that we are laying the foundation for that at this point.

And while you at the ISO are very busy working on the economic and reliability criteria that needs to be accepted by all, when we're making decisions.

CHAIRMAN KEESE: Thank you, Don. At this time I'd just point out our next logical step here, looking at what we have up on the board, is to look at the box that isn't there yet. And that box is represented by some of our other speakers now. And in reference to your allusion to construction, some of the people who have built the major systems that we've had over the last 25 or 30 years.

So, who would like to start on this presentation?

MR. SCHUMANN: Good morning; this is John Schumann for Los Angeles Department of Water and Power.

CHAIRMAN KEESE: Welcome.

MR. SCHUMANN: As an owner of transmission assets and the operator of its --

CHAIRMAN KEESE: I don't know, is that light on? And can you get it about six inches from you? That's better.

MR. SCHUMANN: Is that better?

CHAIRMAN KEESE: Right in front of you.

MR. SCHUMANN: Okay, I'll repeat again. My name is John Schumann representing the Los Angeles Department of Water and Power. As an owner of transmission assets and the operator of its own control area we thank you for the opportunity to present the Los Angeles comments regarding transmission planning, resource development experience, and the outlook for the future.

As a vertically integrated utility Los Angeles utilizes the integrated resource planning process. This is an iterative process, which Ms. McPeak is talking about, where we look at demand side alternatives, transmission alternatives and generation alternatives, and we come up with the least cost solution during that process.

We are currently implementing the IRP that was adopted and approved by the City of Los Angeles August of 2000. It is a blueprint that defines future resource and development activities for generation, transmission and other improvements for our system. Key drivers, system reliability, emission reductions, renewable resources, fuel diversity, distributed generation, conservation, energy efficiency, and most important, competitive electric rates.

We are well on our way. Several repowering projects are in progress inside the basin, which will greatly improve the fuel efficiency of our natural gas-fired plants. That's approximately 2200 megawatts. Completed the installation last year of 280 megawatts of quick-starting peakers for system peaks. Installed approximately 7 megawatts of photovoltaics on our system as part of a $150 million commitment to photovoltaics.

We have also installed approximately 2 megawatts of installed microturbines using landfill gas. The Board last year approved a 40 megawatt biogas project to be located within the City of Los Angeles. And we're currently going through the development process for 120 megawatt wind project to be in service in late 2005.

Further, we're modernizing our Castaic pump storage facility which is going to improve the efficiency of it, not only in pumping but in generation where we will increase the output by over 90 megawatts at that facility.

Our conservation efforts over the last two years, energy efficiency programs have achieved over 150 megawatts of peak load demand reduction.

As we meet today the Board of Water and Power Commissioners is also voting on a proposed modernization of a 17 megawatt small hydro project that's located about 30 miles from Los Angeles.

As you can see, we're very busy. The

projects identified so far and the IRP is well over $2 billion worth of commitment by the Department.

Now specifically transmission. Los Angeles uses a ten-year planning process. It is updated on an annual basis. The process identifies potential constraints, system enhancements to meet native load, and other improvements necessitated by transmission or generation interconnection requests. The analysis follows accepted WECC criteria.

On a regional basis Los Angeles participates and coordinates with various entities, including that we participate in WECC's planning committee and various subcommittees. We're members of the Western Arizona Transmission System Task Force, better known as WATS, which coordinates all east-of-river and west-of-river transmission planning activities.

We participate with Edison and San Diego and with the Cal-ISO at transmission stakeholder meetings. We also participate in joint planning activities with other SCPPA, Southern California Public Power Authority, members.

Examples of these activities we are

currently in. We are assessing the possible upgrade of the east-of-river improvements that we've heard about earlier today. We're also modernizing the Sylmar DC converter station, the southern terminus to the Pacific DC intertie. It's a $118 million project, which co-owners are with Southern California Edison.

We are also, through our analysis, we're improving the intertie between Sylmar and the Cal-ISO by installing a 900 mVa transformer. That's currently in progress. And we're also assessing interconnection request to the DC line to bring on renewable energy facilities located about midway on the DC line.

In addition to these activities we're developing the transmission requirements for the Los Angeles' 120 megawatt wind project located about 100 miles north of Los Angeles. As the lead agency for this project we are collaborating with local and federal governments, including the military, and addressed the siting issues for the machines and the ten-mile transmission tieline. We believe this process can be used as a model on how to work together to achieve a successful outcome.

We will continue to look forward to opportunities to incorporate renewable generation to our transmission system and other resources.

As I mentioned, we collaborate with other owners, operators of transmission systems in the WECC, and encourage cooperative planning to improve the use of transmission systems.

This is a segue into an initiative that is currently underway that will increase power reliability and enhance transmission line access in the west. It is a voluntary collaborative effort under the Public Power Initiative of the West, WPPIW. It has produced a common oasis platform for the posting of available transmission capacity. The independent common oasis site is called westtrans.net, w-e-s-t-t-r-a-n-s.

The effort has been expanded to include private transmission owners and will go live this spring. There are currently 19 participating transmission owners in this process. We believe the cooperative public/private effort will make it easier and more transparent to determine available transmission and ultimately to a more efficient use of the western transmission interconnect.

An item that I'd like to add as

something else the City of Los Angeles is doing now, we are currently holding public hearings regarding the establishment of an RPS. That goes beyond the efforts that I mentioned earlier today. We are currently considering a 20 percent RPS standard by 2017.

And finally, in summary, local planning leads to voluntary collaborative regional planning. We have a common goal: insure reliability; provide benefits to our customers; support competitive bilateral markets; and preserve individual business models within existing regulatory structures.

Thank you.

CHAIRMAN KEESE: Thank you. And since we want to do this as a roundtable, can we -- TANC, are you going to --

MR. FEIDER: Good afternoon. My name is Jim Feider; I'm the Chairman of the Transmission Agency of Northern California. It's a pleasure for me to be here to represent 15 municipal utilities in northern California. We have a rather diverse membership ranging from Redding in the north to Lompoc in the south; from Santa Clara, Palo Alto and Alameda in the Bay Area to

Plumas, Sierra in the mountains. Our largest member is the Sacramento Municipal Utility District. And we also enjoy the membership of Modesto and Turlock Irrigation Districts.

Each of our members' approach towards transmission planning is driven by where's the power coming from; where is the generation coming from. And we have a hard linkage, if you will, between our resource planning and the need for transmission.

Some of our members have generation in their service territory. Some of our members have no generation in their service territory. And some members have generation far removed from our service territories. Redding, for example, where I come from, has coal-fired generation in San Juan, New Mexico.

Again, our transmission plans and our planning process is driven by our resource needs to serve our customers. We acquire our power supply on a firm basis. We expect transmission to be a long-term investment. We expect the transmission investment to secure our investment in resources.

TANC's major project, of course, is the

California/Oregon Transmission project. This was the third AC line that was added to the Pacific AC intertie system between California and the northwest in 1993. TANC invested over $430 million in this project. As you may or may not know, the investor-owned utilities were originally participants in this particular project, and were ultimately turned down by the PUC process.

It's a 430-mile line from the California/Oregon border to the Tracy Tesla area. In 2003 the TANC members stepped up and reinforced the transformer at Tracy substation to solve some of the overloadings that had been identified by the Cal-ISO. That project was done somewhat in parallel with PG&E's reinforcement at Tesla.

Other projects that the northern California munis have participated in include the Mead/Phoenix, Mead/Adelanto and Adelanto/Lugo 500 kV project in the desert southwest that came on in 1996. Modesto and Turlock Irrigation Districts constructed a 230 tie to the Tracy substation in 1995. NCPA, of course, conducted a connection, a 230 kV tie from their Calaveras Hydro in the 1989 timeframe, and added to it in 1994.

Santa Clara is under construction of an

interconnection reinforcement at the 230 kV system level with PG&E. That project will be completed later this year.

The projects that TANC and its members have participated in have benefitted the entire California grid. We look at it on a systemwide basis. For example, when the California/Oregon Transmission project came online it went a long way towards firming up the existing Pacific AC intertie that at that time was rated at 3200 megawatts. It's my belief that that 3200 megawatts could not have been sustained without the addition of the COTP.

The COTP also reduced system losses, so all of Californians enjoy the benefit of reduced system losses. The COTP facilitates outage coordination and provides more flexibility in operation of the 500 kV grid. And it also provided an overall improvement to the remedial action schemes that were in place at the time.

So, again, our emphasis is on transmission projects that are linked to generation. And I would like to emphasize that there's more than a linkage to the power supply aspect of generation. There's also a linkage to the physical interconnection and interplay between the generators that it takes to support the grid. You cannot move power across the grid without the generation support and the physics and the interplay and the dynamics between generation and transmission.

So, we focus on supply to our customers. I would observe that perhaps the case study in southern California from the Miguel substation is one that these bodies here should strongly look at as lessons learned and room for improvement.

Where are the fixes? You've heard a lot about the physical fixes from Armi and others. We certainly agree that the physical fixes that they've identified are in order and well justified.

Again, those fixes need to recognize the interdependence of generation and transmission. Rather than saying that generation is built to serve a market, the generation goes hand-in-hand with the transmission.

We think that from a policy perspective re-establishing that link will go a long way towards making prudent additional fixes to the transmission systems that serve the customers. We applaud the efforts that are underway here to streamline that siting process, the permitting process, as was already mentioned earlier this morning. The public utilities in the State of California are able to effect the permitting process, do the CEQA analysis and have their boards of directors approve the investment.

And it's the linkage of those transmission investments back to our customers that have put us in a good position to support transmission reinforcements.

Path 15, for example, is one that TANC actually provided the CEQA certification back in 1988. Myself and Arch Pugh from Redding chaired those public meetings in the central California area. We would liked to have participated in the Path 15 project, but we couldn't get value for our customers. There was no direct link, as we saw it, between the way Path 15 was being approached and our customers. We are very glad that Path 15 is going forward, and we certainly support its completion.

Thank you for your time. I'll be glad to take any questions.

CHAIRMAN KEESE: Thank you very much.

And I think what we will do here to assist our schedule is we will break at 12:30 for a 45-minute lunch. I will tell you where that can be obtained.

In the meantime that gives us about 17 minutes to do a roundtable here. And I'll just say, for starters, I hear you saying hard-wired, and then I hear you say for the benefit of the whole system, which makes me think I'm turning my head both ways at the same time.

I guess the question that's the more generic question I have is we're looking at a system that was described to us that handles about 70 percent of the load, and perhaps 70 percent of the lines. And you're representing other entities that have another 30 percent.

Can we integrate it better? Do you feel that L.A.'s work, for instance, with the WECC and others makes this fully coordinated? Are there benefits that we can get to, acknowledging that you're not PUC jurisdictional and you don't intend to be?

MR. SCHUMANN: Thank you for stating that for me, so --

(Laughter.)

MR. SCHUMANN: I believe we can always do better planning as a group in California, and we can't forget the southwest. It was mentioned that a lot of our resources are coming from the southwest. We just need to do a better job of collaborating in our planning process. And we'd be more than happy to participate in the planning with the state. We're not an island out there, but we definitely will stay outside the Cal-ISO.

MR. FEIDER: Yeah, the municipal utilities that I represent have been active participants in the planning process for a long time, both at the old WSCC level and now the WECC level. We participate and provide data into the ISO's five-year planning process. And when they identify issues I don't think they stop their analysis at any particular municipal city gate.

And so we are interactive in that planning process. And I think we are not bashful about voicing our concerns if we see a project that either needs to be built and isn't, like Path 15, or if a project is identified that we don't think is necessary.

So, I think we've involved in the various levels of planning, both in the state and on the western regionwide basis. And we certainly think that improvements could be made, as is the case with just about any situation.

CHAIRMAN KEESE: President Peevey.

PRESIDENT PEEVEY: Yeah, John, I want to ask you a question here. You know, when one steps back, try to shed your skin for a moment, or your hat, put yourself outside of DWP for a moment, and you look at transmission planning in California and implementation from a little bit of a distance. What is the argument, what is the argument for not having all the major providers be part of the ISO?

Initially perhaps it was cost, but as we go forward, you know, we have this problem with WAPA now, WAPA wanting to have its own control area. You got SMUD and you got DWP. You have historical reasons for these things. But, as one tries to rationalize a system, looking from a public policy point of view, from here in Sacramento, you know, what are the current or going-forward arguments, in your mind, best ones to keep out of the ISO? We'll concede the PUC, but how about the ISO?

MR. SCHUMANN: Well, you know, I don't

want to go back to the 2000/2001 timeframe when we had problems in the state. California had transmission problems and generation problems. Los Angeles has planned well in advance; has sufficient reserves. We have probably close to 30 percent reserves in generation. We have substantial amounts of transmission capability, north and south, east and west, to serve our customers. Our customers pay for that, and they expect the benefits from it.

So, we want to cooperate in a plan with the state, but the City of Los Angeles has spent a lot of money, a lot of time for a number of years to strengthen their system to where they were not subject to a lot of things that are going on in California.

So, I think that's one of the primary reasons why, you know, we're real hesitant about it. We want to cooperate and want to plan with the state, but not at the jeopardy of what we've accomplished to date.

PRESIDENT PEEVEY: I mean would it be fair to say you want to cooperate, you want to plan and you will, but it's on your terms?

MR. SCHUMANN: No, we'll work together.

We're willing to work together with the state, there's no question about that.

PRESIDENT PEEVEY: On a cooperative basis --

MR. SCHUMANN: Cooperative basis.

PRESIDENT PEEVEY: -- without being a formal member of anything? Well, the ISO --

MR. SCHUMANN: Our system is connected. Like I said, we have the DC line which we have to work with Bonneville on one end, and we work with the Cal-ISO on the other end in order to insure that the transfer of energy occurs across that.

We are the operating agents for a number of switching stations throughout the west where we have a number of member companies, transmission owners, in Arizona and Nevada and in California where we work together on a daily basis.

So, I don't think there's much difference in working within the state.

PRESIDENT PEEVEY: You know, one of the things that we're very interested in here is renewables and you made reference in your comments to when the DC line goes back to the 60s. And it's always started in Oregon and ended at Sylmar, and there's nothing in between. I mean there's no interconnection whatsoever, although there's been talk about it in the past.

Now, you made some reference to maybe interconnection for renewables about half way down. I mean is this something that you look positively toward or not?

MR. SCHUMANN: Of course, we are looking at, we've had more than one request for interconnection to the DC line for bringing in renewables. There is, you know, a cost associated with that and a reliability issue. What we don't want to do is jeopardize the reliability of that DC line. But we are looking at it. We understand the technologies are there to be able to put in a third terminal. And that's what we're looking at now.

We are in the process of assessing that with a number of different partners.

PRESIDENT PEEVEY: I mean you do understand the dilemma, or the challenge to public policy here where the state may put a very high priority on lets' say those renewables, without speaking in any specific source or what-have-you. And you have a different view in terms of reliability of the operation of that line. That potential interconnection could jeopardize reliability to some extent.

Then we have a -- if that was the case, just conjecturally, then we have a conflict. And I'm trying to figure out how that conflict is resolved in the interest of the public as a whole.

UNIDENTIFIED SPEAKER: You don't have to --

PRESIDENT PEEVEY: You don't have to answer that.

MR. SCHUMANN: I'm not going to answer that one, no.

(Laughter.)

PRESIDENT PEEVEY: You don't have to.

ACTING DIRECTOR LLOYD: Chairman Keese, I have a related question. And it probably goes farther than to the folks at the municipalities. It probably goes back to Cal-ISO and others.

And I think the real issue is planning and cost/benefit analysis across boundaries. And I know that there has been a lot of talk about what the economic model is going to do to try and do that, but I mean, for one thing I missed a little piece of that, but it just seems to me that the exchange that just happened here is an example of that.

And I don't see, front and center, enough discussion about what exactly we're doing to deal with the fact that we've got, you know, a PUC process that is IOU-specific, ratepayer-specific; you got a Cal-ISO process which hopefully is taking a broader perspective and is moving in that direction.

How do we integrate those things is really the question for anybody who wants to answer.

CHAIRMAN KEESE: Well, we don't have Western or Bonneville, who are strong participants, certainly in the west, present. Commissioner Wood, who is at a conference in San Diego today that I was at yesterday, we heard the Department of Energy spokesperson, Jimmy Gladfelte, indicate that Bonneville and Western will be involved in the grids if this Administration has anything to do about it.

So there is going to be an effort evidently on the federal level to integrate the federal systems with the state systems.

If it can work --

ACTING DIRECTOR LLOYD: I guess what I

was looking for is what, within our control of these state agencies, are we doing. I think we can always look to what the feds do as a supplement, but what about the effort that's being made at Cal-ISO for the economic model is going to allow us to look beyond just a single service territory. And maybe even look at things that any single service territory wouldn't find beneficial But when looked broadly at the state's overall needs, is really important to do, regardless. And how do we deal with sort of cost-sharing?

CHAIRMAN KEESE: Recognizing that there is no control I think we can do the best to cooperate -- Mr. Perez.

MR. PEREZ: Yeah, trying to answer the question that she just asked, when we applied any of the economic models that we come up with, for example let's look at Palo Verde-Devers. The program not only gives you the cost or the benefits associated with the California ratepayers, it tells you what's happening in Utah and in Arizona and everybody else.

So one of the biggest problems that we have is trying to determine exactly which one of those do you use. Do you use the entire WECC customer base as your guiding light? Or do you use only the California control area guiding light? And it's interesting to listen to some of the discussions.

I wanted to address the reserves issues. I fully understand that reserves in 2000/2001 were probably a lot better in L.A. than they were at the Cal-ISO. But it was not because the reserves were not there. It's because the reserves were not being made available, which is a big difference. I mean, I think the generation was there to carry the peak and plus. But we had a little problem with market manipulation that got us to where we were.

So, one of the things that we're concerned is when you have too many control areas is not sufficient. You have duplicative efforts being made on both sides, both control areas. So, can we be more efficient if L.A. were to join the ISO? I think the answer to that is yes.

There are several ways that could happen in the future, as we try to get a handle on the markets, construction of the market, or market design. There's stuff like metering subsistence that could be used. I mean so there are ways to do it.

So, to me, the main two reasons that in the past have been the factor for different control areas is cost and the loss of control. People that had control over their own control area don't want to give it up. So, we'll have to deal with that.

MR. FEIDER: Mr. Chairman, I'd like to respond on this general topic. I think, first of all, to say that the muni transmission or even the PMA, whether it's Western or Bonneville, is not studied on an integrated basis is not accurate. I think the transmission system is studied on an integrated basis. All the study groups, whether it's within the state or within the entire western United States, is studied.

So, as Armi said, when you have a single -- n-minus-1, and it causes a problem in Utah, people know about it, they know whose system it is on or vice versa. If there's a separate at Four Corners, California has to react. So that part of the system planning and system studies is integrated.

With respect to whether the municipals

are all the way in the California ISO or not, some of us are in in degrees, and greater degrees or lesser degrees. But what we are looking for in northern California is more durability and certainty as to what the market design is, and how we make that link between generation and the load.

And the current California ISO design does not do that for us, we don't believe. And the proposal that the ISO going forward for locational marginal pricing is a step in the wrong direction, and goes away from the certainty that we're looking for.

And so those are some of the reasons we're not all the way in the ISO. We are integrated as a part of the transmission grid. But we want to maintain our ability to serve our customers on a fixed, known and measurable basis.

CHAIRMAN KEESE: Director Vial.

DIRECTOR VIAL: Just for clarification, the ISO pointed out earlier that FERC looks to the ISO for -- and I'm reading from their presentation -- for determinations as to whether new transmission constructed by the PTOs is necessary and cost effective.

Now, we know that not all of the munis

are PTOs in this respect. On the other hand, I'm trying to find out where is it the ISO has some input into muni decisions? It's my understanding, looking at the charts of the CPUC that when the ISO determined needs and reviews alternatives it goes to the WECC regional reliability assessment process. And it's at that point, it's at that point that the ISO can give input to muni transmission projects, is that correct?

MR. FEIDER: Well, I think that's certainly one part of it. I think the other part of it is all of the munis, if they're interconnected with their local investor-owned utility, PG&E in northern California, of course, has interconnection agreements. And those interconnection agreements require coordination with PG&E. PG&E is the PTO in this case, and so therefore if they delegate that planning responsibility to the ISO, then the ISO is a part of that process.

CHAIRMAN KEESE: Mr. Sweeney -- and I would say for the people on the wings, our esteemed guests on the wings here, wave your hand and I might see you here. Mr. Sweeney.

DR. SWEENEY: Thank you, I appreciated

those comments. I did hear a couple of clear statements that I, as an economist, look at as symptoms of suboptimization of the system. I heard statements that some of the TANC investments gave significant investments to the rest of the system, particularly are you're coming in from the Pacific Northwest in some of your plans.

I heard you say that the decision to go ahead in Path 15 with your participation didn't happen because you didn't get benefits, even though you saw benefits for the state.

So this sounds to me like it's exactly what we're hearing from the Commissioners, that there is a real suboptimization going on. And it sounds like, I bet if we look at the investment by the IOUs you'd have a clear, symmetric story. And these may be giving us part of the problem that I believe we all know that we have, it's sort of a less-than-optimal investment in transmission investments.

So from that little background, the question is we know that through the IOS that developing and fairly comprehensive economic, and hopefully environmental optimization model that we understand includes not just the ISO control area, but all of California, plus some of the west.

Would there be payoffs for you to be part of that effort in working with the ISO in the optimization model, and start moving towards a joint optimization of the system through your participation in the Stochastic optimization model that they are putting together? Or is that still not a winning strategy of that degree of cooperation?

MR. FEIDER: I guess my reply to that would be there's always room for some degree of optimization. And if you're talking about trying to squeeze out a few percentage points of optimization and juxtaposed to your obligation to serve your customers, and not knowing if you're going to have firm transmission to serve them, we're not willing to make that tradeoff.

Now, if we can get some certainty in serving our load while we are working in a collaborative effort to get tat optimization we're certainly willing to do that.

MR. SCHUMANN: Yeah, I'm not real optimistic from some of the experiences we've recently had with some of the collaboration we've tried to do with Cal-ISO.

But talking about joint efforts, this process I've mentioned about the public power initiative of the west is a classic example. We have 19 participating transmission owners, Cal-ISO is not a member. We have got 11 western states participating in this. It's a place where we're going to try to optimize use of the existing transmission system and possibly add upgrades, also, throughout the west.

So, you know, we're trying to participate cooperatively, but, you know, I'm not sure what the rest of California is trying to do.

CHAIRMAN KEESE: Thank you.

ACTING CHAIRWOMAN McPEAK: Mr. Chairman. I'm sure that --

CHAIRMAN KEESE: Briefly.

ACTING CHAIRWOMAN McPEAK: -- that Ms. Doll would like to comment on this, but as I'm hearing all of this, the simple answer, and it's probably too simplistic, to the question that Director Lloyd asked a few minutes ago which is, so what do we do and who's in charge.

Well, the fact of the matter is no one's in charge of everything; no one is in control of all of it. But we have taken it upon ourselves because we individually have some responsibility, and collectively presumably have all the responsibility.

We have said, okay, then get everybody in the room and do the plan. And that's essentially where we were trying to drive. With looking at transmission; having accepted the premise that it is, you know, a cross-cutting component to our energy supply that affects every aspect of what we were trying to do on the supply side, that we needed to have everyone together.

Whether or not you're in the ISO or not, we are to be in the same room and presuming to act as if we're functionally integrated. And ask the question, so what is the most important and efficient set of it's transmission facilities we need to keep the lights on.

So, I mean going forward, what I would want to propose is the designation of the responsible folks from all of the people who need to be at the table, such that we come out with a transmission plan by the end of this year. Like, that simple. That's not easy to do. Its simple to say, but that's actually the imperative.

So, Mr. Chairman, you've got your lead.

You've got the PUC folks. Whatever from the municipal side has to be there. That's what I want to suggest we just task.

COMMISSIONER BROWN: Excuse me. What you're suggesting is that we have an action plan for transmission.

ACTING DIRECTOR LLOYD: Yeah.

COMMISSIONER BROWN: Okay.

CHAIRMAN KEESE: And I think that we've made a great start today in establishing and laying out the positions of the parties, where they are, and what we can do.

This is not the only forum that is studying this. It's being studied in probably a dozen forums in the west right now, because there's a broad recognition of the significance of this issue.

And --

COMMISSIONER BOYD: Mr. Chairman, --

CHAIRMAN KEESE: -- McPeak, I think as we've done before, we can task our staffs to take the next step. Mr. Boyd.

COMMISSIONER BOYD: Well, I hate to prolong your agony here with time, but Ms. Doll started this off today, and I'm going to give her a chance to have the last word, because I wrote down something she said, having learned her lesson of writing quotes of what people said in previous meetings and play them back to them.

But you said, as you introduced this, planning is not the problem, quote. And then we listened to, all the past hour we listened to the PUC lay out a whole litany of lack of comprehensive planning, balkanization, redundancies, et cetera, et cetera, et cetera.

Are you sticking with that comment? Was that tongue-in-cheek? Or did you have something else in mind, something that maybe hasn't sunk in? Or maybe it did, maybe it's the balkanization I've heard that exists between various agencies, not of the planning process. But what did you mean, to give you the last word.

MS. DOLL: Well, that's a great lead-in, and I appreciate it. Here's one of the things that I'm struck by after this hour-long discussion.

We have actually not heard this morning disagreement about specific projects that have been brought before and are currently at the PUC and ISO and even at the munis. Nobody stood up before you and said -- now maybe they did that just because this isn't the forum.

But for example, Mission Miguel needs to be moved forward, as does Jefferson-Martin, Martin-to-Hunter's Point, Palo Verde-Devers #2, maybe something at the Tehachapi. I heard about Moss Landing, Imperial Valley into San Diego, just as an example of some specific projects that I don't think there's a lot of disagreement about the need for those projects.

But what I was just asking Barbara was, okay, best case, when would the first of those projects come online. So her answer was we figure about three years from now.

COTP took how long? Maury, you were there at the beginning, and, Jim, from --

MR. FEIDER: Well, initially the deal was put together originally in 1984, and it came online in 1993, so a little less than ten years.

MS. DOLL: It's a good example. And, again, I'm not talking about the projects that Barbara referenced earlier that are more the, I forget the terminology, but kind of bread-and-butter, the upgrades and so forth that are being done within the utilities. But these projects that might actually allow more power to flow among the state at regions seem to take longer. You know, for whatever reason.

But the planning point, Commissioner Boyd, was a lot of planning has gone into getting this list together. And so there they are. And now they're trying to move forward. And I would suggest that they are not moving forward because of a planning problem.

CHAIRMAN KEESE: Thank you

COMMISSIONER BOYD: So Secretary McPeak was correct in her challenge.

CHAIRMAN KEESE: Thank you.

MS. DOLL: There would be one other thing that I would say, though. There is one other sector that we haven't heard from today. Sam Wehn from Babcock and Brown is here. And I know that --

CHAIRMAN KEESE: And if he's going to be here this afternoon, is that --

MS. DOLL: I'll pass around --

CHAIRMAN KEESE: We're going to break right now. Let me give you the dynamics. We will give you a slightly adjusted agenda when we come back, when we return after we've done a little caucusing here.

If you would like to speak this afternoon we ask that you fill in one of the blue cards so that we know that.

We're going to start exactly at 1:30. There is a snack shop upstairs which cannot accommodate everybody in this room. There is a hamburger joint in the office building 2000, which is -- tell me which way across the street. Directly east.

At the corner of -- we are at 10th and P? Between 9th and 10th on P. I'm sorry, we're between O and P --

UNIDENTIFIED SPEAKER: Wherever we are.

(Laughter.)

CHAIRMAN KEESE: At 12th and O, if you're familiar with it, the Secretary of State Cafeteria, where they do require an ID, has salads, sandwiches and hot food. Vallejo's is down there, a Mexican upscale. And LaBou, where you can get sandwiches and other things. So, there are three facilities at the corner of 12th and O.

UNIDENTIFIED SPEAKER: Are you telling us that --

CHAIRMAN KEESE: Two and a half blocks down here.

We're going to try to start at 1:30. Thank you, everyone.

(Whereupon, at 12:38 p.m., the meeting was adjourned, to reconvene at 1:30 p.m., this same day.)

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AFTERNOON SESSION 1:34 p.m.

CHAIRMAN KEESE: Can we take our seats, please, and we will get started, the hour of 1:30 having arrived.

We have a slightly revised agenda. And since it was prepared, the agenda has been revised one more time.

Mr. Wehn, would you like to describe to us the DC proposal from Pittsburg to San Francisco?

MR. WEHN: Yes, sir, my name is Sam Wehn. I'm representing Babcock and Brown. They are headquartered in San Francisco.

I want to thank you for permitting me to make a brief presentation about the transbay cable project. As you know, there have been a lot of effort evolved over the last few years to try to provide a San Francisco energy solution. And what I'm about to propose to you is just a, call it another opportunity for us to solve the San Francisco energy problems.

Some of the things that have happened in the past or maybe more recently are the peakers that are being proposed in San Francisco, about 180 megawatts. The Jefferson-to-Martin transmission line. And neither of those projects have any impact on our project that we're proposing.

Specifically our project is a DC cable project that's going to originate in the City of Pittsburg. It will be connected into the substation, PG&E substation, located in Pittsburg. And it will run from there. And we have three possible routes that we are considering. And it will have another converter station located down in San Francisco, probably in what we're looking at right now would be the Potrero Power Plant location. So somewhere in that area is where we would visualize a second converter station.

The DC technology is, the cable is about five inches in diameter. There will be two cables that will be laid from San Francisco to Pittsburg. And the three different vendors that we have been talking to at this point is ABB, Siemens and Alstrom. We're hoping that we can resolve who is going to be the selected OEM or vendor for our project by the end of March.

This project is being done in cooperation and in conjunction with the City of Pittsburg. So it's a joint effort with the City of Pittsburg actually owning the project.

And we're planning, as a financing arm, the Babcock and Brown organization to provide the financing for it.

The control of this line, it is intended that we would transfer that control over to the California ISO upon commercial operation.

As far as the environmental process, we're looking to have the City of Pittsburg be the lead agency in environmentally evaluating our project. And as you probably can imagine, the bulk of this line, as well as one of the converters, two converter stations, is located in Contra Costa County. So the bulk of the project basically is a Contra Costa County project.

I think we've already -- as a matter of fact, I know we've already filed a determination of need. And the thought process here is that within the next four to six months we're hoping to get a resolution on the determination of need, as well as we would like to file or start the environmental process.

If everything goes as we would hope for it to schedule itself out, the idea would be to have a commercial operation sometime in late 2006.

And candidly, we have really not much else that we have put into place. We are actually talking to a number of people including PG&E. We've actually made a presentation that we've passed out to you, to the executives of PG&E, prior to actually going on the street and talking to anyone about it. So they're in support of our project and we're looking for continued support from them, as well.

That's a brief description. There's a lot more detail I'm sure that we're going to generate over time. And we're planning to keep everyone informed as we go forward.

COMMISSIONER BROWN: Sam, just give us an illustration of what your process starts with.

MR. WEHN: With regard to?

COMMISSIONER BROWN: Anything.

MR. WEHN: Well, the idea is to file a notice of determination from an environmental point of view. File a notice of determination environmentally, and start that process. Our expectation is somewhere around July, August of this year.

COMMISSIONER BROWN: Where do you file that?

MR. WEHN: We're going to --

COMMISSIONER BROWN: Where do you file that?

MR. WEHN: With the City of Pittsburg.

COMMISSIONER BROWN: Okay.

MR. WEHN: They'll be the lead agency.

COMMISSIONER BROWN: Um-hum.

MR. WEHN: And then the plan is to have a series of -- do the complete CEQA process through the City of Pittsburg with public meetings that are going to be held throughout the one-year process.

COMMISSIONER BROWN: And then where does it go? Do you have to go to BCDC?

MR. WEHN: Part of our permitting process will be to BCDC.

COMMISSIONER BROWN: Will they have a CEQA review, themselves?

MR. WEHN: The plan is that they will not.

COMMISSIONER BROWN: Okay.

MR. WEHN: That they will join in with the City of Pittsburg.

COMMISSIONER BROWN: Okay. And then how about with the PUC, what do you have to file with those guys?

MR. WEHN: The City of Pittsburg is a municipal, and they don't have jurisdiction under the PUC.

COMMISSIONER BROWN: Okay, does the PUC have any role in it at all?

MR. WEHN: At this point we don't see any role with the CPUC.

COMMISSIONER BROWN: And you don't have approval problems, or you don't have a preapproval processes with ISO, right?

MR. WEHN: I'm not sure I understood what you --

COMMISSIONER BROWN: In other words, ISO doesn't have to come in at any stage -- oh, it does, huh?

MR. WEHN: Well, I would say they do.

COMMISSIONER BROWN: Later on.

MR. PEREZ: The way the project is planned for funding is similar to the transelect project. That means that they would like to get all the cost recovery from the shareholders. That means I have to make a determine the project is needed, or it doesn't go forward.

COMMISSIONER BROWN: That's with the ISO?

MR. PEREZ: Yes.

COMMISSIONER BROWN: Okay. Does the PUC come in at any point?

MR. PEREZ: I don't believe so.

COMMISSIONER BROWN: Okay.

(Parties speaking simultaneously.)

ACTING CHAIRWOMAN McPEAK: -- be the ISO and then FERC.

MR. PEREZ: Yes, then it would go to FERC, right.

PRESIDENT PEEVEY: Theoretically the PUC could. I mean there's a converter station at Potrero Hill, and that has to be converted. It has to then go into the PG&E system. There's some costs presumably to be borne there. You're saying you would bear all the costs?

MR. WEHN: Yeah, that's the plan. It would be a cost-based --

PRESIDENT PEEVEY: There would be no cost to PG&E?

MR. WEHN: That's the intent; it would be a cost-based solution. If there are upgrades then the project would have to pay the upgrades.

PRESIDENT PEEVEY: But PG&E has to file with the Commission under 851, right? Unless --

no?

COMMISSIONER BROWN: No, it could probably be just like Path 15 where we bow out of it. But theoretically, the PUC could claim authority here. There's no question about it.

PRESIDENT PEEVEY: And then, of course, the big meat grinder is the City of San Francisco, right?

COMMISSIONER BROWN: Well, they're very pro these kind of things, aren't they?

PRESIDENT PEEVEY: I was 22 years in city government, and I pity you.

(Laughter.)

CHAIRMAN KEESE: Thank you. Let me just say that our plan, after this morning's discussion in transmission, is to challenge our three executives with preparing a summary and a recommended addition to the action plan on this issue if such is necessary. And present it to our next Steering Committee meeting.

We would ask that you, since we have not heard all the details of this project, that we include the details of this project. Of course, the muni involvement I would think would be appropriate to have the Western and BPA involvement. And the results of the other presentations we saw this morning.

So, --

MR. THERKELSEN: And you want that summary simple, and our next meeting is when, December, I think?

(Laughter.)

CHAIRMAN KEESE: You heard me correctly.

(Laughter.)

CHAIRMAN KEESE: Okay. Thank you, thank you very much.

What we're going to do now is we're going to move to goal V, promote customer and utility-owned distributed generation. We've shortened this presentation to 20 minutes.

Then we're going to hear from each of the -- from PG&E and Edison in five-minute presentations.

And then we will move to public comments and member discussion from up here.

So, without further ado I will turn it over to, Mr. Rawson, are you doing this, or who is?

MR. RAWSON: Actually it's going to be a joint presentation by my colleague, Dan Adler from the PUC, and myself.

CHAIRMAN KEESE: Thank you. Mr. Adler.

MR. ADLER: Good afternoon. I'm going to walk briefly through present CPUC DG related activities, and give you a little overview of what's to come from the PUC before turning it over to Mark.

The PUC's principle DG program is the self generation incentive program. These numbers are our most recent. In 2003 we have approved funding for 92 megawatts of clean and renewable DG projects. The 210 megawatts since July 2001 is a funding level, not necessarily an interconnection level.

These eligible types of generators you may be familiar with. This is the standard for our program. This program compliments the CEC's buydown program; the CEC is targeting smaller systems of similar technologies.

Recent activities include the departing load decision which exempted certain categories of clean DG from DWR costs. We adopted that in 2003, April.

We made permanent the expanded -- this is kind of an extended gibberish here -- but basically we made larger the size of technologies that are eligible for our net metering program.

We adopted a pilot net metering program for small biogas fueled DG. Eliminated standby rates through 2011 for these renewable and super-clean DG, assuming they were connected before June of this year.

And then interim process for utility procurement of non-utility DG for distribution support.

All of these programs and activities are in some sense interim or standby, pending the opening of our new DG rulemaking, which is meant to take a broader look at DG technologies for utility procurement, as well as appropriate incentive levels.

The present structure of CPUC SGIP incentives is listed here. 450 a watt up to 50 percent of installed costs for the renewable DG technologies. Scaling downward for fossil fuels, either by fuel cell or by direct combustion.

Presently we have a mid program evaluation of the SGIP to evaluate its effectiveness in meeting the mandates of AB-970, which is kind of the guiding legislation for our

DG programs.

We are reviewing the comments and they have been substantial, and actually quite helpful. And we're anticipating a proposed decision in June of this year on how to update our SGIP in light of those comments.

The issues in those comments include adjusting the funding levels between categories of technologies; decreasing the dollars per watt incentives. This is something we've received a lot of feedback on, and actually seen some good experiences from other commissions and DG programs around the country. This effectively creates a market-like discipline in the DG incentive program.

The percentage caps, a lot of our commentators have suggested there's a distorting effect in having up to 50 percent or some number to that effect. And we are considering perhaps removing caps and going with a strict dollar value cap on project size.

And we are working to incorporate AB-1685 emissions and eligibility requirements into our SGIP program.

This is, to my mind, going to be the

principal venue for DG policy at the CPUC in the future. It's been pending for quite some time now. From the staff's perspective it's very close and I anticipate that it will be ready in the very near term for Commission review and adoption.

This is a very broad overview of what we'd be looking at. This notion of the cost/benefit analysis has been pending before the Commission for probably two years now, as the sort of driving force in how we decide when to incorporate DG and how to fit it in the utility program. And how to design our incentive programs.

Again, revisiting the incentive levels, taking a look at how DG can best be used in utility procurement. Spoke to that issue in the recent long-term plan decision in January, directing the utility to be more specific in their planned use of DG as an actual line item in their procurement plan.

And finally, hopefully standardizing definitions of distributed generation which I think will aid all DG policy going forward.

One thing I'll mention that's not on here that I know has been of interest to this body, we have begun the process of incorporating renewable DG into the RPS program. For instance, solar facilities on homeowner rooftops will be, at some point, assuming that we can work out the details, eligible to credit the relevant utilities RPS targets, assuming that the property rights are properly allocated between the homeowner and the utility. It must be a transaction that properly accounts for the homeowner's investment in that process.

But this creates, again, to my mind, a very powerful potential incentive for much more insulation of solar facilities on new homes and on existing homes. It's very difficult to project how this will be adopted, but I think it could be, in addition to the cash incentives we provide, a very nice additional incentive for the RPS.

CHAIRMAN KEESE: Thank you.

MR. ADLER: Turn it over to Mark.

MR. RAWSON: Good afternoon; my name is Mark Rawson. I'm actually wearing two hats in this presentation. I've recently been tasked with helping to coordinate DG activities here at the Commission; and then the last two years I've been program manager in one of the PIER research areas, specifically looking at the integration of DER technologies into California's power system.

I'm going to give you just a quick policy context, and then I want to give a status on some of the Commission's activities, ranging from the implementation/commercialization side, and end up with some discussion about some of our research and development activities in the DG integration area.

As you're aware, action item V is to promote customer and utility-owned DG. The PUC and the Energy Commission have worked collaboratively on a variety of areas in the past, and were planning to do so in a much more coordinated fashion in the future in the areas of targeting research and development, looking at the cumulative energy system impacts from integration of DG into the power system, and looking farther out to the future about what the impacts of new technologies are and how they're used.

Bob Therkelsen talked a little earlier about the IEPR. Basically this slide just shows that the loading order strategy that's advocated in the energy action plan is similar in the IEPR report, and that DG plays a role in several components of the strategy in terms of renewable DG's ability to accelerate our RPS goals; the ability of distributed generation to defer either distribution or transmission planning; and then lastly, DG as a customer alternative to meet specific reliability or power quality needs.

The Energy Commission and the PUC have done a lot of work in this area. And this doesn't represent all the state agencies that have been doing work in the area of DG. But what this slide shows is that the principal energy agencies have been involved in DG to address a variety of different issues. Some of these issues have been checked off the list, and other issues still need to be resolved. Dan mentioned cost/benefit as an area of interest for this new rulemaking. And I'm going to give some updates on specific Energy Commission activities next.

Dan mentioned that the CPUC had adopted a decision to address the departing load fees. The Energy Commission has been working collaboratively with the PUC on now implementing that exemption process. And we've accomplished several important milestones since that decision was made in April.

In October of this last year we adopted regulations for the exemptions. I think we made record time in adoption of regulations and set a new record here at the Commission. This was a fairly involved process. We had numerous workshops and hearings to arrive at agreed-upon regulations with interested parties.

In January those regulations became effective. And just last week the Commission approved the application forms that the utilities will be using with their customers. And yesterday opened the doors for business and began receiving applications. I think officially now we have received three applications here at the Commission. So things are moving along.

With respect to the utilities administering the tariffs, the PUC is presently reviewing the advice letter filings. We're waiting for approval of those filings so that the utilities can begin their work administering the tariffs.

With respect to DG interconnection, this is an area where the Commission and the CPUC have been collaborating for a number of years. But that collaboration is broader than just the tow agencies. It's a collaboration between utilities, DG equipment manufacturers and end users.

And this slide represents really the results of that successful collaboration. The standardized rules that were developed through this forum, and have been improved upon in collaboration with utilities and users and manufacturers, have resulted in standardized rules, standardized schedule for how applications are processed; set fees that are collected to process those applications. And this slide really highlights the fruits of those labors.

Approximately 560 megawatts proposed since the new rule went into effect in December. And of that, 376 new megawatts approved and/or operational.

We're seeing consistent increases in the number of applications since this rule's adopted each year.

Talking a little bit about the complementary program that the Energy Commission has to the CPUC's self-generation incentive program. Our emerging renewables program provides incentives for smaller renewable systems such as photovoltaics, small wind, renewable fuel cells.

And the status of this program thus far, there's been a large request for incentives for renewable DG; upwards of $227 million. 7800 systems have been installed to date, totaling about 30 megawatts. And there's about $46 million still available in this program.

What's interesting to note here is that the level of activity or number of applications that have been submitted against the Energy Commission's program doubled in 2003 compared to 2002, upwards of almost 8000 applications. So we've seen a lot of increase in activity for this incentives program.

I want to talk a little bit about the research activities here at the Commission relative to distributed generation. As part of the Public Interest Energy Research program, DG has been a significant portion of that portfolio of R&D. To date there's been over 100 projects that are DG related, totaling over $94 million of the $370 million that PIER has encumbered to date. This represents about a 25 percent investment in the portfolio towards DG related issues.

The PIER program has six main program

areas and all of the program areas have some level of DG related R&D being conducted.

What we see in this slide is that the principal focus so far in the DG research arena has been focused on improving the environmental impacts of DG technologies and reducing the cost of these technologies to make them more competitive.

Across the bottom of the slide are the six program areas within the PIER program, and down the vertical are some of the key issue areas that the research portfolio has been focused on

Most of the activity within the research program has been in both the environmentally preferred advanced generation program which is focused on fossil DG technologies and the renewables technologies in the renewables program.

The energy systems integration group which is in the middle is the program area that I've been involved with over the last year and a half. And this is an area within PIER that's probably the newest in terms of research activities to try to address some of the integration barriers that DG faces today.

Initially our work was focused on

developing standardized interconnection rules for California. Of late, our emphasis has grown more into the grid effects and integration area. And we've been investing research dollars to understand how DG will affect the operation of the distribution system, how much the distribution system today can absorb before there may be adverse impacts, and conversely, understanding how the distributions system is operated so that the benefits of distributed generation can provide can be dispatched or optimized to help the system.

It's out of this particular research area that a lot of the research will be beneficial to the new rulemaking that the PUC will be embarking on here shortly. Myself and other staff here at the Commission are working collaboratively staff-to-staff with the PUC on this new rulemaking that they will be releasing. And we will be bringing to bear the results of our research activities across the whole PIER program to help provide good analytics to the issues that they want to address in this new rulemaking.

We've also engaged key staff at the PUC to sit in an advisory role on some of our research activities to give us the perspective of issues that the regulators are concerned with with respect to distributed generation.

So, moving forward, the research activities that the Commission has been leading in the PIER program are going to be directly linked to the policy issues that the PUC is trying to address with respect to distributed generation.

Are there any questions?

CHAIRMAN KEESE: Thank you. Any questions for either of our speakers, here?

ACTING CHAIRWOMAN McPEAK: What is it going to take to accelerate the adoption of the technologies that are cutting edge and get to scale so that we can also drive costs, since you're talking about sort of the inner relationship between costs and pursuing the policy?

MR. RAWSON: Well, there's -- I think the principal drivers that are going to drive the DG market are going to be the benefits that it provides the direct end use customer that's installing the technology.

But what we're finding in our research is that there are other benefits that distributed generation can provide, whether they be environmental benefits or benefits to the distribution system. And mechanisms for getting at those benefits need to be put in place.

And the research activities that we've been focused on and some of the issues that the PUC is looking to address are going to look at how do we unlock those other benefits that distributed generation can provide to the system more environmentally. So that's one of the areas where I think this new rulemaking is going to help shed some light on what some of these other market mechanisms are, and how we get them implemented.

MR. ADLER: I'll add one point. I think to the extent that we reorient our SGIP subsidy funds away from technologies that are relatively mature and in the direction of those that are more experimental and need more public subsidy, to reach that point of market maturity, that will help bring these more to sort of a market-based developmental position.

And, again, the RPS opening for renewable technologies provides a subsequent revenue stream that could support these advanced DG technologies.

CHAIRMAN KEESE: Thank you. Any other

questions here?

ACTING CHAIRWOMAN McPEAK: I have a comment.

CHAIRMAN KEESE: A comment.

ACTING CHAIRWOMAN McPEAK: A comment. And I'll end it with a question to Ms. Doll. In the distributed generation section there is one component that the CPA is supposed to be taking a lead in, and actually with Secretary Chrisman, who was here, --

CHAIRMAN KEESE: Just stepped out.

ACTING CHAIRWOMAN McPEAK: Okay, I looked down and Mike left, okay -- and Secretary Tamminen and Secretary Aguire we're trying to actually do the installation, solar installation on state-owned buildings. And I think with the involvement of the three agencies that we might actually have made some progress.

But I'm wondering if Ms. Doll could just report on where we are. And then also Dan Skopec took the time to also get a briefing. And Dan's no longer in the room, either. But this is one in which we are really having to push very hard to get done.

MS. DOLL: We are, and we'll make sure

that Dan gets a briefing, as well. We are currently on track to issue an RFB before the end of March, and we have the commitment of the Department of General Services to make that happen.

And the intent there is to go out to the market and ask developers to provide bids for about six specific state facilities that have been identified by the agencies as good candidates for solar photovoltaic installations.

The developers would be asked to install, to give us a price on installing the PV system and providing power to the state agency in exchange for a contract to provide that power, and the developer would then receive a per kilowatt hour payment for the energy produced from the system.

So this is a third-party model which we're hopeful will bring in some proposals and allow the state to actually begin to implement SB-XX-82 by Murray Brulte that was passed three years ago in a way that doesn't require the state to put money up front.

So, I have whined to you all about this many times before. We've overcome some of the hurdles and right now we're cautiously optimistic that we'll actually be able to get something on the street. Looking forward to participation and support from the Energy Commission which we are getting in terms of value, how we can evaluate those proposals once they come in.

And are really thinking that this will be a program that once it has gone through the incubation process of this summer, will be able to be managed by the Department of General Services.

CHAIRMAN KEESE: The Secretary McPeak suggested might be a candidate for discussion at one of our future meetings.

And I would use this point to say that Mr. Stephen Heckeroth, who was here this morning and had to leave, wanted to enter on the renewable resource program. He suggests performance-based incentives for solar energy, including monitoring a solar tariff and low-interest loan programs. We'll distribute this to everybody later.

Thank you very much for that discussion on distributed generation.

We'll go to the investor-owned utilities and we'd like a presentation. Gary, you're closest to the mike. And Mr. Schoonyan knows, I will ask everybody who does come to the mike if they would have a business card out for our reporter, it will make things much easier. Thank you.

MR. SCHOONYAN: He already has it.

CHAIRMAN KEESE: I knew he would.

MR. SCHOONYAN: Thank you, Mr. Chairman. Gary Schoonyan, Southern California Edison Company. Appreciate the opportunity to be here to address the three Commissions, and other agencies.

What I want to do is update you on some of our efforts with regards to the energy action plan, and then comment on a couple of the presentations, particularly in the area of transmission, that went on today. And I'll try to keep it within five minutes.

With regards to renewables, we're looking at achieving the 20 percent goal this year, 2004. We believe that that's doable at this point in time, given the resources that we have in place. We aren't stopping there, though. And that's significant, when I say 20 percent for Edison, we're talking over 13 billion kilowatt hours which represents one-sixth of the national total of renewable power. I mean it's a huge amount; more than any other state.

But we're not stopping there. We have a couple of RFPs out right now that are being evaluated and will be submitted to the Commission before this summer to basically somewhat expand upon that, but more than that is to make sure that we carry the 20 percent on through the period of time. Because we do have some existing renewables that their contracts terminate or whatever is happening. They may not, who knows. We want to make sure that we're at least at or better than the 20 percent going forward.

And as I mentioned, we will be coming forward to the Utilities Commission and present the results of those, which frankly, I can't get into details, I found to be very favorable to the renewable community. They were good projects. And more than just one good project.

With regards to -- oh, one other thing, too, even though it wasn't a part here, we exercised our option on Mountainview the end of last month or yesterday or sometime. And we want to commend the Commission --

CHAIRMAN KEESE: Not on April Fool's Day.

MR. SCHOONYAN: No, no, --

CHAIRMAN KEESE: Don't tell me --

(Laughter.)

MR. SCHOONYAN: We commend both the Utilities Commission and FERC for basically looking at this one-of-a-kind type of option and proceeding very quickly to do the necessary things. It's very beneficial to our consumers. And basically all the information associated with the costing of that project is out there available. It's transparent. And it's a good project by any step.

I'm going to talk just briefly about DG. We, since 1996, have close to 2100 interconnection agreements for 275 megawatts, primarily in the photovoltaic. You saw on the previous chart that it was about 155, 200 thereabouts of the fossil DG. It's primarily photovoltaic. We've actually participated and helped restructure the efforts to standardize rule 21 that made a lot of this possible.

And I want to say, you know, one of the things that we do feel that needs to be considered in pursing the DG debate is to address it from a consumer protection perspective as much as a technology roll-out perspective. I think the focus to date is primarily incentives and things necessary to promote DG, which we're not adverse to, per se, but at some point in time the consumers that are footing that bill need to get something back. And there was some discussion a few minutes ago about unlocking the benefits associated, environmental benefits and other things.

That's fine. We have no problem with unlocking those benefits. It's just that we'd like to see those benefits flow to the consumers that have funded the subsidies, not to the generators and the projects, themselves.

Finally, I want to touch, and I'll probably spend a little more time on the transmission issue. We have indicated before that the current CPCN method for siting major, and I want to emphasize major, transmission projects is over litigious, fragmented and uncoordinated and needs to be repaired.

I do want to emphasize the major, the vast majority, well over 95 percent of our projects are the smaller ones that Barbara Hale talked about. And the processes at the Commission are very well implemented. We get those done rather quickly. And there's been no problems there. And the one thing we want to make sure of is as we attempt to streamline and focus on the major projects, that we don't do things that upset the applecart on the smaller ones that represent well over 95 percent of the effort. Because that program is working very well at the Utilities Commission at this point in time.

But we do need to streamline the process, cut down all the litigious manner that we go through where typically good projects are held hostage for the proverbial better. There was some discussion with regards to CEQA being a roadblock. I've been involved in the licensing of three transmission projects. And CEQA, from an environmental perspective, hasn't been the roadblock. CEQA, from the perspective of looking at alternatives, particularly the no-project alternative, has been one of the biggest hurdles that had to been overcome.

And that gets to the need question. And I think that was pretty well addressed earlier today.

Other things with regards to this, in

long lines of coordinating with other agencies, is to recognize the role of the PTOs. That's, you know, what about me type of deal. I mean the utilities do offer a significant amount; I mean we do primarily most of the preplanning for facilities before we submit them to the Independent System Operator and other agencies.

We have a very legitimate and valuable role in the process. And frankly I think it needs to be identified and emphasized a little bit more than has been discussed today.

The final thing is a recognition, and there was quite a bit of discussion about benefits, economic and reliability benefits. There's also, particularly I've seen with transmission projects, there's this so-called strategic benefits or long-term benefits that no on can really capture. And even probablistic approaches tend not to always capture some of the benefits.

Give you some examples. Pacific intertie. I'm dating myself now. But there was a project that had a one-to-one benefit/cost ratio. It would not probably have gone forward, but for the trees that were required with the Canadian government and all that other stuff.

However, as a result of that transmission being in place, I can recall because I was actively involved, is one year where Edison alone saved $600 million. More than paid for all of the investment in that transmission project. One year.

Also because of that transmission project we were able to basically expand and really nurture the California power pool, which was sort of a precursor to a lot of the pooling that's gone on in the state to date. That has huge benefits in the area of reducing reserve margins, coordination between utilities, taking advantage of diversity between areas. That was a result of that transmission project that would have never been identified in a traditional economic type of an assessment.

Third is the State Water Project. Here's a 2000 megawatt State Water Project that would have had a difficult time being built but for having the backbone transmission system in place.

I guess what I'm getting at is I have yet to see a transmission project that didn't pay for itself on things that were never identified in the original analysis or the application. And that needs to be considered in anything that goes forward.

The final thing I just wanted to touch upon, there was some discussion on D-PV #2. We're going to get final internal approval this month on the 18th. We'll be submitting our filing with the ISO for them to get approval. Concurrent with that we'll be filing with the Public Utilities Commission the end of this month, first of April, as well as concurrent with that be going to the WECC to get a rating of the facility, itself. So we're looking down several different paths simultaneously to move forward on that project.

Thank you.

CHAIRMAN KEESE: Thank you very much. Les. And then we'll take comments from the panelists.

MR. GULIASI: Good afternoon. Les Guliasi with Pacific Gas and Electric Company. This morning I sent to each of you Commissioners and Directors a letter that briefly summarizes some of PG&E's activities that addressed the three topics that we were discussing today. I'm not going to spend much time, because in the interest of time I think I can just hit some of the highlights and let us get on with the program.

With respect to the first topic today, the renewable resource goal, PG&E is fully committed to achieving the legislative mandate. We've made significant progress over the last couple of years in increasing the amount of renewable power in our portfolio.

Our recent filing with the Public Utilities Commission estimates that we'll be at 15 percent by 2008. We're eager to do what we can to accelerate the increase in the renewables in our portfolio.

There are still some hurdles ahead of us. The PUC is addressing some of the major issues. Achieving a credit-worthy status is still utmost in our minds. And I believe with the progress we're making and regulatory guideposts that will be put in the ground very soon with the Public Utilities Commission, we will be doing much more to accelerate the number, the percentages of the renewables in our portfolio.

As people here at the Energy Commission know, we have been very active in the western renewable energy generation information system. We think that's a significant effort that will go a long way to assisting the renewables community, knowing what is expected of them and we think that there's a lot to be said for that process, so all stakeholders and consumers will benefit.

Moving on to the next topic, the electricity and distribution infrastructure. As you know, we're in the business of infrastructure development. We have vast transmission and distribution holdings. We have, over the past several years, either planned or have projects underway or recently completed, significant enhancements to our transmission and our distribution system.

In order to serve our more than 4 million electricity customers we have invested over $1 billion over the last four years; we anticipate spending nearly another $2 billion over the next five years in our transmission system. In addition, we spend about $650 million per year in our distribution system.

We've heard a lot this morning about some of the notable projects, the Path 15s, the Trivalley project, the Jefferson-Martin transmission project and others, and as Mr. Schoonyan just mentioned, there are many activities that go on kind of under the radar screen, you know, away from these major projects that are in the headlights and so forth. But we are spending an -- amount of money, resources and time insuring that we make the proper investments in both our transmission and our distribution system to make sure that our system operates safely and reliably.

With respect to distributed generation, we have been fully in support of the many legislative initiatives that have paved the way for distributed generation in the State of California. We have been working with the Public Utilities Commission and other stakeholders in the process to insure that we have a transparent process

We have also spent a lot of time retooling our internal procedures to make the process of interconnection easy for consumers and for developers through the self generation incentive program. We have 78 projects currently online. We have over 250 other projects that are actively in the process.

Some of the most notable projects are the solar photovoltaic facility at the Moscone Center in San Francisco. We have worked creatively whenever possible to package the distributed generation incentive program and our other energy efficiency programs to bring as much benefit as we can to the customers. One success story along those lines is what we've done at Sonoma State University.

We've been inspired by the California Power Authority's interest in promoting solar facilities in state buildings. We have some work underway back at the ranch trying to figure out a way to promote solar installations, photovoltaic installations in schools. So you may be hearing more about that project in the coming weeks or months.

With that I think I can end here, and if you have any questions I'd be happy to entertain them.

CHAIRMAN KEESE: Thank you. Let me get one more speaker in here. We'll hear from Sempra, Dan.

DR. OZENNE: My name is Dan Ozenne. I'm representing the Sempra Energy Utilities, San

Diego Gas and Electric and SoCalGas.

I'm glad to be here today. SDG&E and SoCal have supported the energy action plan from its inception. In fact, SDG&E's long-term resource plan and pending RFP look a lot like the energy action plan's loading order.

We started with reducing demand through energy efficiency and demand response programs. We're increasing supplies from renewable resources. We're trying to obtain generation and supplies in the San Diego region. And we're attempting to build more transmission to bring in more cost effective power to our area.

The energy action plan was an important first step in working toward coordination among the state's energy agencies, and we applaud that effort. It's important for the state not to let up in its efforts to bring stability back to the state's energy markets.

SDG&E has taken and is prepared to take additional steps in each of the priority ares. However, the state must match those steps with prompt action.

My remaining comments I'll focus primarily on the three topics on today's agenda, starting with renewables. What we are doing. SDG&E has aggressively pursued the development of new renewable resources, and as a result has been able to beat the annual renewable targets the state has set.

While we have made great strides over the last two years, we still have to contract to procure significant amounts of renewables in order to achieve the 20 percent. As you all know, we started far back in the pack from the other utilities.

SDG&E has completed two auctions since the RPS was adopted. One specifically for renewables, the other a combination of renewable and non-renewable for grid reliability. SDG&E's reliability RFP identified 40 megawatts of renewable generation. We've increased our supply of renewables by 2.85 percent in 2003, and expect to purchase an additional 2 percent, which will be then approximately 5 percent of our total in 2004, well ahead of the RPS schedule.

We've already indicated to each of the Commissioner's offices that we are prepared to be the first utility to seek additional renewables through an RFP process this year. We've identified some roadblocks to achieve in the RPS targets. The primary ones relate to two transmission facilities required in accessing renewables. As you all know, we're at the end of the line and it's hard to get stuff into San Diego.

What the state must do. The PUC needs to finish its renewable portfolio standards process for determining least cost/best fit market benchmarks, market price referent, and standard contract terms in according with the RPS requirements.

The state needs to address realistically the potential for renewables and what is needed to access those renewables. For example, the CPUC identified 400 megawatts of wind in the San Diego area. To date, SDG&E is unaware of any planned development that would result in resource additions at or near that level.

Further, even if the actual level of development of renewables was 400 megawatts, it would equal only about one-half of our requirements by 2017. The PUC says nothing about how we access the rest, or what happens if this 400 megawatts does not fully develop. We need the lines to connect our system across forest lands to the areas where those renewables will be developed.

The state needs to facilitate access to renewables if we're going to get close to this achieving the RPS target whatever year we set as our goal. The state needs to establish a structure to facilitate fast-track permitting for transmission, to access renewables and corridors to run that transmission through.

The state needs to develop a system of tradeable, renewable energy credits. There's very little opportunity for us to build renewables within our service territory. But we could invest in renewable projects outside of the territory if there were credits available.

CHAIRMAN KEESE: And as you heard this morning, we hope to have a system up --

DR. OZENNE: Hope to have one. Turning to transmission infrastructure, we appreciate that all three of the agencies are confronting the transmission streamlining. We think that's a critical need. We also appreciate the framework that the PUC's transmission OII in eliminating duplication need finding.

What we are doing. SDG&E develops annually a transmission resource plan. And as we've heard others this morning, that's to be integrated in resource planning later. We will be tying this directly into our long-term integrated plan this year. SDG&E has diligently sought to expand transmission in its area and to connect to other areas to accommodate imports, improve reliability and give it greater resource options, primarily through renewables.

We have worked closely with the ISO to identify needed facilities. And we have, on a timely basis, presented needed facilities to the PUC for approval. Two primary examples are Mission Miguel, which I'll not go into since I think there was pretty much uniform consensus that that project needs to move forward quickly. And our Valley Rainbow project, which we still believe is a critical need, as the quote from Debbie Reed, our CEO, this morning. Those projects are needed for San Diego to meet its reliability and its resource needs in the future.

What the state must do. Prove that transmission can be sited and built in California. Process transmission applications with reasonable speed. Unless the state backs up its rhetoric about the need for infrastructure with real action we will see reliability degrade and cost consumers increase.

The transmission OIR could be a good first step if it's not mired in the same political delays that have jeopardized all transmission to the state.

Coordinate among state agencies. For example, deferring to the ISO on the issues of transmission need is a very positive first step. Avoid duplicative regulation where the same issue is tried in several proceedings before several regulatory bodies. And finally, complete the Miguel Mission EIR and approve the CPCN by June.

On distributed generation, what we're doing, SDG&E developed a planning process that the Commission adopted to incorporate consideration of distributed generation in the distribution planning process. SDG&E has applied this program in its operation and is working on documenting procedures to assist prospective developers.

SDG&E has developed a sustainable communities program that integrates renewable DG with the distribution system, consistent with the principles of sustainable energy use. Our first project in this is pending before the CPUC as part of our cost of service settlement.

What the state must do. Endorse and facilitate sustainable communities. Allow for implementation of the CPUC decision on distributed generation and do not re-litigate issues already considered. Insure that the state's goal of supporting DG does not degrade reliability or raise costs to other customers. This is a point I think you've heard from the other utilities, as well. That while we're well aware of the benefits, we also have to be careful that this does not increase costs for other customers.

I think that, you know, it's been stated before and I'll just repeat, that a current renewable DG should count towards the utilities' RPS goals. And we're glad to hear that the PUC is looking into RPS credits in this area.

That concludes my comments.

CHAIRMAN KEESE: Thank you very much.

COMMISSIONER BROWN: I have a comment on the Rainbow.

CHAIRMAN KEESE: Commissioner Brown.

COMMISSIONER BROWN: Since I was one of

the dissenters on that project and I've been hearing about it from Jim ever since, he looks at me like Darth Vader.

I would, you know, I made the suggestion to other people after the vote, and that is that I think that really the Sempra SDG&E should really start to work harder in the Temecula Valley with those folks. I think that something like that is feasible, would pass the Commission. But I think the company has to do a better job of working with that community.

CHAIRMAN KEESE: Thank you. Commissioner Geesman.

COMMISSIONER GEESMAN: I wanted to add to what my friend Geoff said. I didn't vote on the proceeding; it didn't come in front of our Commission. Maybe that will change some day.

Let me explain that Terry Winter, the CEO of the ISO, told a number of people that when he worked at San Diego Gas and Electric, went in to their CEO in 1979, suggested, you know, we're going to need a line here. We ought to go forward and acquire right-of-way.

The CEO at the time, Tom Page, said, well, can you tell me that we're going to need this line and use it in the next seven years. Terry said no, but I know we're going to need a line there. The CEO said, well, our lawyers tell us that we cannot use our powers of eminent domain if we're not going to use the facility within the next seven years.

As a consequence nothing happened and it ultimately came before your Commission with 45,000 more residents in the Temecula area than was the case in 1979. I would suggest that it's our obligation to figure out a way to avoid that problem because it will recur somewhere else 25 years from now. And the opportunity that we have, since we all seem to get along, is to move forward in identifying where those lines in the future will be, and begin the right-of-way acquisition process now.

COMMISSIONER BROWN: I couldn't agree with you more. I mean, we really have to -- this is really part of your transition to transmission action plan, and that is, as you suggest, define those routes so that you're not literally uprooting communities or disturbing communities.

I mean the political firepower that's brought to bear when a transmission line is proposed is just enormous. Aside from the merits or anything else like that. And, you know, it takes all of the powers of persuasion that a utility can bring to a community to try and convince them that, you know, this thing is not going to be obtrusive.

COMMISSIONER KENNEDY: Mr.. Chairman.

CHAIRMAN KEESE: Thank you. Ms. Kennedy.

COMMISSIONER KENNEDY: I actually have another question on Mission Miguel, but as somebody who voted for Valley Rainbow I'd say you probably need to tunnel under Temecula at this point in order to build that.

The question I have is on Mission Miguel. I thought it was April it had to be completed by the Commission. It's June?

DR. OZENNE: The information that I had said June, yeah.

COMMISSIONER KENNEDY: And what happens if it's not approved -- if the CPCN is not issued by the PUC by June? What happens to the project?

DR. OZENNE: Well, there's just additional delays in construction and --

COMMISSIONER KENNEDY: There's always

delays. I understood that you were going to lose a year? Do you have any --

DR. OZENNE: A year, yeah.

COMMISSIONER KENNEDY: So, if it's not approved by June, you lose what?

DR. OZENNE: I think we lose seven to 12 months in the construction of the project.

COMMISSIONER KENNEDY: Thank you.

CHAIRMAN KEESE: Thank you. What I wanted to point out particularly for our guests here that what the action plan has been, in a little over a year of existence, is an action plan, a plan to move forward.

And as we've held now, this is our fourth or fifth one of these plenaries, what we found was we need the feedback and the utilities can give it to us. So we have decided that every time we do this we're going to ask the utilities to give us input to let us know whether we're on the right track.

That's one of the reasons that the Steering Committee asked you to join us, because we're hoping we get the same feedback from you. We hope you find what we're doing beneficial. But we'd like your input as to where we should be going and whether we're doing it in the right way.

This is now Commissioner time. We have limited individuals in the audience who have asked to speak. So I will say for any of the people up here, and our guests, if you'd like to probe any of the issues that have been before us, feel free.

Sunne.

ACTING CHAIRWOMAN McPEAK: Mr. Chairman, I do want to thank all three of the investor-owned utilities for having initiated the practice, and now we're adopting, to officially list you on the agenda so that you are, you know, reporting to the public the progress. But also then specifically identifying what we need to do. That's very helpful.

I think also, Mr. Chairman, that we have intended to invite the public-owned utilities, through whatever mechanism, if it's CMUA or whomever, to also adopt that practice, as well as the independent power producers. So that if there's other who think that they should be reporting to the public and sharing, we would want to recognize them and not exclude them.

Jarry, thought I was calling on you? Well, MR. JORDAN: Well, since you asked, I'd be happy to tell you what --

ACTING CHAIRWOMAN McPEAK: Can I just -- just before you talk, though, Mr. Jordan, I just wanted to point out that before lunch Jim Detmers said the same thing. And during lunch B.B. Blevins said the same thing as I think you did, Commissioner Geesman, which is we need to be looking farther out.

And actually the constraint we have on being able to preserve those paths has to be tackled. I mean that's a legal issue that we should identify and move forward on it.

I also wanted to respond in terms of the state needing to have a sustainable communities or sustainable developments smart growth policy. I think Secretary Chrisman and I are aware we've been charged with trying to, as a cabinet, integrate the various approaches and values into a new program that can transcend all the departments and all the agencies on something like smart growth for the new Administration.

And then I'll defer my question to SDG&E after.

CHAIRMAN KEESE: Mr. Jordan.

MR. JORDAN: Since you asked.

CHAIRMAN KEESE: Since you asked I'm glad you had prepared --

MR. JORDAN: I thought I'd give you a very brief update on where we are on RPS standards and I was very pleased today to hear that the investor-owned utilities are finally trying to catch up with municipal utilities as it relates to renewables.

And I can tell you we've just recently done a survey. We don't have 100 percent of the utilities reporting back yet, all the returns are not in. But I can tell you that from what I have here, and I'll be submitting that to you in written form as soon as it's complete, indicates that most of the municipal utilities are at least meeting, and a whole bunch of them are exceeding, the goal that is being asked of the investor-owned utilities.

For example, the City of Alameda is 80 percent renewable and 50 percent eligible renewable. The City of Healdsburg is 80 percent renewable and 53.2 percent eligible renewable. The City of Lodi is currently 48 percent renewable and 25 percent eligible renewable.

The City of Santa Clara is 65 percent renewable and 25 percent eligible renewable. The Trinity Public Utility District is 100 percent renewable. The City of Ukiah is currently 75 percent renewable and 53 percent eligible renewable.

Nearly everybody else has adopted a goal of 20 percent by 2017. We haven't asked them about accelerating that date yet.

I'll submit more complete information in writing.

UNIDENTIFIED SPEAKER: jarry, what's eligible (inaudible).

MR. JORDAN: Eligible, by the standard that is in SB-1078, because I didn't know before that the rain didn't fall on large dams.

(Laughter.)

CHAIRMAN KEESE: There's a question that has been raised about which god decided that 30 megawatts was a significant number.

(Laughter.)

CHAIRMAN KEESE: Smutny, why don't you --

MR. SMUTNY-JONES: The answer, Mr. Chairman, was his name was Peace. I was there when it happened.

(Laughter.)

MR. SMUTNY-JONES: Thank you very much. And I wanted to follow up on something you said previously, Mr. Chair, about this being an action plan. And we would like to see the action actually put into the plan.

We're having an incredible sense of d,ja vu here. It seems like just yesterday, although it was ten years ago, that we had just completed a six-year process with both agencies through an electricity report and something called the biennial resource plan update, which resulted in an auction and then nothing happened.

And my concern is we seem to be headed down that same path. We're doing a lot of planning. We seem to be getting ready to wallow all summer long in workshops. But meanwhile there's some real opportunities going by.

And so I have a suggestion, because I was asked two weeks ago to come up with something practical, and my something practical is put 5000 megawatts out to bid over the next four years in an open, transparent, competitive process.

Now, this conservatively is within the

energy action plan's proposal of 1500 to 2000 megawatts per year. It's a little below the 1500. It is within the bandwidth of what the ISO believes is a very potential of losing up to 6000, maybe more, megawatts of existing use due to early retirement. And it's not likely to disrupt the orderly shift of core/noncore market if that subsequently becomes a reality.

I think you heard previously today from Mr. Schoonyan that they feel quite comfortable about moving ahead with major build-outs. We think if they believe that that's prudent, that that should apply across the board.

I believe it's somewhere in the neighborhood of over 18,000 megawatts of power plant sites have been licensed since 1999. And about 8200 megawatts of that has been built out. And forgive me for the loose math, but that leaves about 10,000 megawatts of currently licensed sites that could be developed, which generally takes between 18 and 24 months, if actually given an opportunity.

I think there's a tremendous potential out there right now to add additional new renewables so Mr. Jordan can move his 2017 forward, to repower much of the existing infrastructure that's out there. And to add new generation. I think this will give us a clear indication, also where you're going to need to be adding new transmission. And you can do this within the context of all the energy efficiency and the other issues that you have out there.

But we need to act. We're missing some opportunities. Now is the time to act. You have the opportunity to do that. And while I love to plan, and while I love to attend workshops, I would actually love to attend some plant openings. So I appreciate the opportunity to comment today and look forward to some action.

CHAIRMAN KEESE: Thank you.

COMMISSIONER BROWN: We have a groundbreaking coming up soon in southern California near Redlands.

MR. SMUTNY-JONES: I'm sure I'll be invited.

(Laughter.)

CHAIRMAN KEESE: Commissioner Brown.

COMMISSIONER BROWN: No, I was going to ask Commissioner Peevey, my colleague, what he thought of the prospect of putting 5000 megawatts out there for bid.

UNIDENTIFIED SPEAKER: Put him on the spot, Geoff.

PRESIDENT PEEVEY: Let's take a very careful look at that, through strategic planning.

(Laughter.)

COMMISSIONER BROWN: I just thought I'd like to get an answer without having to go to a single workshop.

UNIDENTIFIED SPEAKER: We do them in due time.

CHAIRMAN KEESE: Secretary McPeak.

ACTING CHAIRWOMAN McPEAK: Well, Mr. Chairman, actually I would appreciate being enlightened about why not. Because it seems to me why shouldn't we do this. I'd like to see the results.

CHAIRMAN KEESE: Ms. Hale.

MS. HALE: As a person who just heard the suggestion for the first time moments ago I have a couple of just basic reactions.

First of all, in our procurement decision our agency thought it was prudent. The Public Utilities Commission thought it was prudent to plan for a future where there may be core/

noncore market design. Which means to us that you may have the investor-owned utilities providing for less load. Is that compatible with signing up, in the near term, 5000 additional megawatts for California?

And if we were to pursue 5000 additional megawatts on top of the opportunities we've already taken advantage of, are we creating a new set of stranded costs that we'd have to address?

We recognized, as a group, through the energy action plan that we're currently in a hybrid market. Direct access is suspended. We're encouraging infrastructure development in a very uncertain environment. We've had several pieces of legislation proposed that would settle what the retail market environment is, but none of them have gotten beyond introduction.

And we'd like to see, at least, you know, at the staff level, in conversation with Commissioners, we've talked about, at the PUC, we'd like to see some more certainty in the marketplace in the retail market responsibilities before we jump to additional large obligations for the investor-owned utilities.

So we're trying to plan for a future

that's responsive and flexible depending on what comes out of Sacramento in terms of the next steps for our retail market design.

It's an uncertain future. Planning in that uncertain future environment is very difficult, you know. There's aspects of what Mr. Smutny-Jones suggests that sounds appealing, but you have to think about the complexities for what it may do for your options in retail market design in the future.

CHAIRMAN KEESE: Mr. Vial.

DIRECTOR VIAL: Well, along these lines, Jan started out by referring to the BRPU process, and referring to d,ja vu. That was under PURPA when we were dealing with the beginnings of a hybrid system.

Since then our system has become a hell of a lot more hybrid. And we are now re-engaging our IOUs in the planning process in a system that I think is going to become more hybrid.

I was wondering how, you know, maybe you don't want to answer this today, but I think it would be good for the utilities that have the experience of the BRPU process, before it was derailed for deregulation, and now take a look at how we're re-engaging the utilities now in this more hybrid system, but as a key player in the planning process. And how you look at the options and what have changed that makes it different from the BRPU process.

Just thinking of it in terms of the wholesale market, we have a lot of short-term contracts we'd like to see forward contracting that is extended out to the future longer. I think it would be good to have some response from the utilities in how they look at their role in a hybrid system.

Because there's also the suggestion that since we no longer -- well, when we had cost-of-service regulation we had the utilities, a vertically integrated utility, and we had put all of the responsibility on you for doing the planning and being the initiators of the planning.

Under a hybrid system I'm wondering how much responsibility can be put on the load serving entity, and how much of the direction has to come more from a planning process that we are now getting engaged in.

I don't know if that's too clear, but I really do think that it's important for us to get a better view of how the utilities are looking at their role in planning as they become re-engaged in a much more hybrid system.

CHAIRMAN KEESE: Well, I'll jump in and suggest that there seems to be unanimity that failure to have long-term contracts played a significant factor in our short-term bad history. And that somehow or other we have to get to some form of longer term arrangements as part of a portfolio. I don't think that's really disagreed with.

But what we're hearing is that we need a stabilized marketplace from Smutny and from the PUC. That we need to know what the marketplace is before either of us can move.

Now, that calls for action. Because we do need that stabilization. We need the stabilization between the ISO and FERC; we need the stabilization between PUC and ISO. We need to get a stabilized market so people can participate in it. Unless somebody disagrees, long-term contracting is going to be on the table. It may be on the table, but we're not -- it's not on a short term.

DIRECTOR VIAL: If I just may, when we

dealing with the BRPU process we were dealing with avoided costs and the utility was integrating alternative energy into their planning system. This is not a question of avoided cost anymore. We're talking about a wholesale market that's becoming mainstream in the planning process.

CHAIRMAN KEESE: Ms. McPeak.

ACTING CHAIRWOMAN McPEAK: What I'm hearing all sounds right. It's just that we need to somehow reconcile it. And I guess, I think we have the people here that can do it.

If it's -- the certainty in the marketplace issue of core/noncore was raised by the PUC at one of our past steering committees, and we've been trying to try to figure out exactly what that is. I'm going to turn to Mr. Skopec and say, we actually need to have -- and Dan knows that, we all know that collectively, the Administration. We've got to get that decision. At least some direction.

I think that, you know, it's right that the utilities are cautious because they've gotten pretty burned in a very flawed, deregulated or reregulated environment. At the same time we are, in our own energy action plan, suggesting we really do need, even optimizing all of the conservation, all the demand management, all of the renewables we can possibly think of, we're going to need to have more generation so that we're not caught short.

You know, the ISO is today a little bit more comfortable because we've had a lot of rain. I still think there's a sense of urgency, and that there must be something worth pursuing in a competitive bid. I don't know how it gets managed. But I would suggest that that is worth further discussion with our executive officers and the parties that be to explore that concept. And if we need to, talk to the person who's renegotiating those long-term contracts that are out there.

CHAIRMAN KEESE: Ms. Kennedy.

COMMISSIONER KENNEDY: We're leaving the impression that this is like all or nothing; it's either go out with 5000 megawatts for bid right now or sit here and do nothing. And I don't think that's the case. I don't think that's a reflection of what's actually happening.

The procurement decision actually does begin the process of putting out to bid for a certain amount of megawatts, albeit incrementally a portion of what was suggested by Mr. Smutny-Jones.

But the action plan, as he pointed out, calls for an even greater amount of electricity generation to be brought online over the next couple of years. And so I don't -- I'm not hearing that there's an all or nothing here.

I think what I'm hearing is we should be -- we have the ability to be more aggressive in our bid process to bring more generation online. Perhaps even be more aggressive without solution yet about what the market's going to look like. Because we know we need generation. We know that just for the growth in the core market we're going to need generation.

But I don't know what -- how many megawatts we're going out with in the next couple of years. I don't remember from the procurement decision. I don't know where the safe line would be to increase that over the next couple of years in anticipation of a core market growth before you then potentially are going into a cost-shifting or stranded cost situation, if in fact we do go to a core/noncore.

But I would probably agree with Mr. Smutny-Jones that there's room there to be more aggressive if we choose to be more aggressive.

CHAIRMAN KEESE: Thank you. Do we have any -- Gary, feel free.

MR. SCHOONYAN: I was just curious what --

CHAIRMAN KEESE: From the mike, please, so that we can get it on the tape.

MR. SCHOONYAN: Gary Schoonyan, Edison. I was just curious if you wanted us to attempt a response right now to the challenge that Director Vial --

CHAIRMAN KEESE: I wasn't going to throw that to you, but --

MR. SCHOONYAN: -- put forth or --

DIRECTOR VIAL: I was just trying to plant the idea that we need to talk about it in the future.

MR. SCHOONYAN: Okay.

CHAIRMAN KEESE: Yeah, we may be able to structure it a little bit -- sure, --

PRESIDENT PEEVEY: Well, Gary, do you need 2500 new more megawatts in addition to Mountainview in the next two or three years, as

Mr. Smutny-Jones seems to imply? Yes or no?

MR. SCHOONYAN: There is a need for additional generating capacity. We're not going to say that that's --

PRESIDENT PEEVEY: By when?

MR. SCHOONYAN: -- not the problem. And you tell me what the customer base is, President Peevey.

PRESIDENT PEEVEY: Well, this is just circular, then.

MR. SCHOONYAN: That's the problem, is the fact is it core/non --

PRESIDENT PEEVEY: This is circular. We're not getting anywhere talking like this.

MR. SCHOONYAN: I understand. There is a need in the state for infrastructure. We definitely know that. The biggest concern, I thought it was put forth very well by Barbara Hale, is the uncertainty is who you're planning and purchasing and procuring for.

A core/noncore at 500 kW and above is 30 percent of our load. If you layer on aggregation, you go down to 200 kW and above for core/noncore, that 's 50 percent of our load. At 50 percent of our load we have no need. At 30 percent of our load we probably have no need.

So, you got to kind of figure out what the rule -- who you're planning for and who you're procuring for in going forward.

You also need some certainty on cost recovery. Mr. Smutny-Jones' clients have it through the AB-57 and the contracting. As far as utility investments, to the extent that we do it anymore, who knows, there isn't that same assurance. And I think the Commission recognizes in the Mountainview decision, it said once that assurance is in place, if it's in place, then Mountainview we can tear up the PPA and we make it traditional.

So there is a recognition. There needs to be cost recovery assurance, as well as a predictable customer base for everyone to plan for. Not just utilities, but for ESPs, for community choice aggregators and what-have-you. Everyone struggling with who are their customer base, who are they procuring and planning for.

PRESIDENT PEEVEY: How do you have a predictable customer base and have competition at the same time? It's the antithesis of predictability, isn't it?

MR. SCHOONYAN: There's two different types of competition. There's wholesale competition and retail competition.

PRESIDENT PEEVEY: Okay, well, let's talk about --

MR. SCHOONYAN: Customer base is more of a retail thing. It defines your thing. To the extent that you have need, then there's wholesale competition, which has gone on for a long period of time. And actually right now over 60 percent of our load is served by Jan's clients. So there's been a lot of competition gone on, and he's served a large portion of our load going forward right now.

So it's not to say that we've cut them out or anything like that. They have more than we have.

COMMISSIONER BROWN: Is Jan really saying lift the direct access suspension? Is that really what he's saying?

MR. SCHOONYAN: No.

COMMISSIONER BROWN: No?

MR. SCHOONYAN: No. No, the statement, Jan is correct. Jan is correct. Commissioner Brown, Jan is correct, the state needs infrastructure.

COMMISSIONER BROWN: Right, we know that.

MR. SCHOONYAN: It's just that who's going to sign on the bottomline to commit 30 years for a very, you know, for expensive projects without certainty as to who --

COMMISSIONER BROWN: Okay.

MR. SCHOONYAN: -- you're planning for and your cost recovery.

COMMISSIONER BROWN: Okay.

PRESIDENT PEEVEY: All I'm trying to get, I don't think your response was to my question. Maybe you didn't understand it. All I was trying to say, Gary, was the following. You want certainty as to what your retail load is. You want -- right?

MR. SCHOONYAN: Correct.

PRESIDENT PEEVEY: Okay. Close to it. But then you have community choice and you have core/noncore. And isn't, by definition, competition the antithesis of certainty? And don't you have to live with a significant degree of uncertainty? And the question is how much can you live with that's tolerable? What are the bounds?

MR. SCHOONYAN: It's a question of how you manage the uncertainty. I mean the kicker here is, as you all know, this isn't an ordinary business. It's a very unique product. And as a result there has to be some -- it's not a typical market, per se. You just can't turn it off.

COMMISSIONER ROSENFELD: Mr. Chairman.

CHAIRMAN KEESE: I -- can I -- I have Mr. Sweeney. Mr. Sweeney's first; Joe Desmond second.

DR. SWEENEY: Yes. I have a question for each of the utilities. Since we've gone into the issue of core/noncore model, and if you'd just bear with me and accept an assumption that we might want to go to a core/noncore model, that's sort of a 500 kilowatt peak. Let's scale it at that as sort of the cutting line.

And in doing that there's a lot of different proposals about the degree of certainty that utilities need. I think in one bill in the Legislature now that's introduced by Assemblyman Nunes, says you can get out but you got to give us five years advance notice. Which sort of assures that you'll kill off any competition.

What's a reasonable length of time that you can really need for advance notice? Can you live with two years advance notice for a company to -- a customer to leave? Or one-year advance notice? You, of course, build a portfolio that would be different, that would support the core elect are the ones that can leave then from the core customers.

But what do you really need? One year, two years advance notice? What shorter than five is necessary?

UNIDENTIFIED SPEAKER: Time out.

(Laughter.)

CHAIRMAN KEESE: Do you want to go off the record, Gary?

MR. SCHOONYAN: Well, first of all, --

(Laughter.)

MR. SCHOONYAN: Yeah, first of all, --

DR. SWEENEY: Just thought I'd ask.

MR. SCHOONYAN: -- as I understand the Nunes bill, it's an immediate, they have an immediate option to opt out. And if they decide to stay, then it's the five years. So it isn't five years from the get-go.

As far as the five-year lead time I

believe that's typically the time required to do something like to get licensed, from day one, a combustion turbine type thing. Can you live with a shorter time period? You probably could to the extent that you're uncertain.

I mean it all depends on how much, I mean five years makes sense if you have a huge uncertainty of, you know, 25 percent of your system out there and your load's only growing at 2 percent, and you're covering half of that because of energy efficiency, because that's the right thing to do.

That's one thing. So to the extent you're exposure for losing customers is a lot smaller, then potentially lead times could be smaller, as well. Because the time to respond without incurring significant stranded costs, you can do it.

Anyway, that's off the top of my head, but that's how I looked at it.

CHAIRMAN KEESE: Joe.

MR. GULIASI: I'm sorry that I can't be more specific; I think there really isn't a direct answer to your question with respect to, you know, a finite number of years. I just think that there are, as Gary Schoonyan was trying to explain, there are other factors that it's really a question of managing risk and understanding the degree of uncertainty.

I think, you know, from a customer perspective, if we could just take a customer perspective, you want to have very flexible rules. And, you know, I mean I'd hate to say something like, you know, a week's notice or a day's notice. But you got to have some way of managing from the utility's perspective the amount of risk. From the customer perspective, even a year seems like an awful long period of time.

And we, as a state, have struggled with this issue now since, you know, AB-1890, and we haven't come up with an answer. And I'm afraid that there just really isn't, you know, a finite answer that can be given at this point until we kind of understand what the risk is and how to mitigate it.

PRESIDENT PEEVEY: You know, there's a slight air of unreality to this discussion. In the old days, well before AB-1890, go back in the '80s, the early '90s, and the '70s, and the utilities in California lost load every year.

Lost load to self generation; lost load for a whole series of reasons. And I was a part of the system. We made assumptions about what that load would be. We absorbed it in our system. We did probability analyses and all kinds of other things.

Now we act like, my god, if you lost 300 megawatts in a year that somehow the whole roof would fall. It's absolutely, I mean it's not true. It wasn't true then; it isn't true now. We used to wring our hands and run off to the PUC and say, we need to have, you know, marginal costs plus a mil to keep XYZ oil refinery on the system. And more often than not we got our way. Or this chemical plant and that.

And the meantime we drove the steel industry out of California; and the anhydrous ammonia industry out of California. And a whole series of other things with bad policy decisions.

But the fact is that we act like we need this certainty, and in fact, you can build in some degree of uncertainty to any system and still make the system viable and workable.

CHAIRMAN KEESE: Thank you.

PRESIDENT PEEVEY: That will produce a

reaction --

CHAIRMAN KEESE: Mr. Desmond. We have two more, we're going to take two more questions here.

MR. DESMOND: Okay, actually these are just a few observations and comments listening through that. I direct them at both the CPA and the CEC and the CPUC Staff on a number of items.

First off, get the easy stuff out of the way. I had the opportunity to sit through a presentation early -- excuse me, late last week on a performance contract at a federal prison that combined performance contract for HVAC controls, but also brought in a wind power at 750 kW, along with 66 kW PV.

And so my question to CPA is as they think about the state projects that they want to issue the RFP for, I think one of the emerging models might be to standardize some of the contract provisions, as has been done with more traditional energy efficiency where you can actually combine energy efficiency with some of the renewables and do so using third-party money.

So that's just an observation. The first project of its kind, as I said, is kicking off. I think the groundbreaking is scheduled for later this month. So, that's observation one.

Observation two is the phase one results on the indirect costs with the renewables on the system. I think I'd like to see them brought into some of the discussions on the resource adequacy, because they get to the deliverability, given the calculations on the loss of load probability, as it relates to the capacity values of the different resources.

So I'm hoping that the information that the CEC has begun to develop is actually brought into that forum when the CPUC holds its workshops.

Second point, then, is as I mentioned in my opening remarks, we've been working a lot with other organizations on the resource adequacy issue. And what our objectives there to provide for. Physical accounting of that capacity, along with the proper incentives for generators to invest in those resources on a long-term basis.

One of the elements of the plan that we've been working on is essentially a physical accounting of these resources through a mechanism conducted by some third-party entity. What I would simply point out is once that mechanism is in place, as it has been done elsewhere, in New York and PJM, it also provides the basis for accomplishing what the western region system is intended to do. And that is if I can identify capacity tax against a physical resource, that resource being supply or demand side, defining that resource as a green resource or a non-green resource is simply another property to assign in the database.

So my only point is I would hope that in the effort to develop this accounting system on the west-wide basis, that the efforts and the energy that's been put in, and the information that's been brought together is, again, brought to the table in the discussions of the resource adequacy.

And the reason I have that concern is I know in California legislatively the CEC's mandated to develop this mechanism. And we heard about the good faith statements on some of the other western governors that are working to this, but I don't know that it carries the same requirement to comply. And I certainly wouldn't want to see a system where California develops and then complies, and the other states don't quite meet the need, if you want to insure the import/ export tracking of green tax.

So, that's sort of the last comment I have is that in the resource adequacy process that we're about to wade into here in these workshops is that hopefully there's the opportunity to take advantage of some of the work and not create duplicate efforts.

CHAIRMAN KEESE: Thank you. Commissioner Geesman.

COMMISSIONER GEESMAN: I had a question for Gary Schoonyan. And that is how do you satisfy -- how does Edison satisfy itself on cost recovery for investments in transmission and distribution? So much of the debate has been focused on generation.

MR. SCHOONYAN: There is statutory assurance associated with distribution and transmission, as I recall. It was a part of AB-995 which did a couple of things. One is extended the PGC through 2011. It also had basically a distribution, transmission distribution system infrastructure type of provisions whereby there was the guaranteed recovery for reasonable investments.

COMMISSIONER GEESMAN: So you would feel that's adequately covered in existing law?

MR. SCHOONYAN: Correct.

COMMISSIONER GEESMAN: Thank you.

CHAIRMAN KEESE: Thank you. The hour of 3:00 having arrived, I will ask if any of our other guests, Secretary Chrisman, any closing comments here? Dan? Pass. Anybody up on the -- well, thank you. I'm going to let Commissioner Peevey close for us.

PRESIDENT PEEVEY: Commissioner Peevey is going to close by saying thank you. I think we've had a pretty exhaustive airing of things here for five hours, and there's not much point to prolong it. So, thank you all for being here. We look forward to having another meeting in another quarter.

CHAIRMAN KEESE: Secretary McPeak.

ACTING CHAIRWOMAN McPEAK: I want to follow on that comment by President Peevey and just ask that we set a given day of the quarter for the plenary session, such as -- I mean this worked. It was the first Tuesday of the third month of the quarter.

PRESIDENT PEEVEY: That would be?

ACTING CHAIRWOMAN McPEAK: Well, it would be June; it would be the first Tuesday in June. And the first Tuesday in --

CHAIRMAN KEESE: Our staff is going to take care of that.

ACTING CHAIRWOMAN McPEAK: But get it set. I mean --

CHAIRMAN KEESE: We'll get it set very --

ACTING CHAIRWOMAN McPEAK: -- standard. Thank you.

CHAIRMAN KEESE: All right. Thank you, everybody, for joining us.

(Whereupon, at 3:06 p.m., the meeting was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission/California Power Authority/ California Public Utilities Commission Joint Meeting; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said meeting, nor in any way interested in outcome of said meeting.

IN WITNESS WHEREOF, I have hereunto set my hand this 4th day of March, 2004.